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Bedir, Abdulkadir

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Abdulkadir Bedir

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Policy Entrepreneurship and Technical Challenges

By

ABDULKADIR BEDIR
B.S. (Istanbul Technical University) 2008
M.S. (Tennessee Technological University) 2010
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Approved:

Joan M. Ogden, Chair

Mark Lubell

Daniel Sperling

Committee in Charge

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Integrating Plug-in Electric Vehicles into California's Grid System:
Policy Entrepreneurship and Technical Challenges

Abstract

The deployment of large numbers of plug-in electric vehicles (PEVs), in order to satisfy zero-emission-vehicle (ZEV) goals in the State of California, brings both potential benefits and costs for the electric grid. Since early 2009, the issue of so-called *vehicle-grid integration* (VGI) has become a center-stage policy discussion among the electricity and transportation sectors. This dissertation encompasses three studies related to VGI. By conducting a policy process analysis, the first study addresses the questions of how the policy process for VGI regulations has been formed in California, and what have been the major challenges in policy-making. A series of interviews were conducted between March 2013 and April 2014 including representatives of 18 organizations from the government, electric utility, and PEV sectors. The qualitative data is analyzed under the three dimensions of policy process; *problem, politics, and policy* as suggested by Multiple Streams framework (Kingdon, 1995). The results show that a policy window for VGI was opened for the first time by the political stream, through State Senate Bill 626 in 2009, and later, supported by the Governor's ZEV action plan in 2012. These legislations gave California Public Utilities Commission (CPUC) the authority to implement regulations on enabling PEV load management systems and PEV-based grid services. In response, Energy Division Staff at CPUC became a policy entrepreneur, and has adopted an incremental policy-making strategy targeting investor-owned utilities (IOUs). The two largest

barriers facing an effective policy solution are identified as; (1) the complexities involved in quantifying economic value from VGI; and (2) the feasibility concerns about adopting VGI enabling technologies on the grid.

The second study focuses on the VGI feasibility issues mentioned above. This study provides a feasibility assessment, focusing on technical and market challenges in VGI. The assessment is performed based on a qualitative analysis of expert opinions gathered by the same interviews used in Chapter-1. The qualitative data is analyzed under three categories of load management, which include dynamic pricing, demand response, and energy storage. The results show that both, technical and market challenges exist in each of the load management strategies. The findings feature a list of technical and market challenges that need to be taken into consideration by stakeholders in VGI-related decision-making.

Finally, the third study develops a stochastic-systems approach to VGI modeling where PEV load management strategies are compared for their economic value to PEV consumers and their local utility companies. The proposed methodology is demonstrated through the assessment of VGI for the Sacramento Municipal Utility District (SMUD). This utility region is studied since it represents a mid-size utility company that provides dynamic-pricing programs for PEV consumers. Monte-Carlo simulations are performed to randomly assign PEV charging characteristics of the households based on given statistical distributions. The proposed methodology provides several improvements to the VGI modeling literature. These improvements include combining assessments for generation and distribution systems in the same model, and advancing uncertainty analysis for PEV consumer behavior considering real-world data sets.

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Finally, and most importantly, I want to express a deep appreciation to my wife, Erica Anderson, for her love and support during my time in the graduate school.

Disclaimer:

The vehicle-grid integration model in this study does not aim to test grid capabilities of the Sacramento Municipal Utility District (SMUD). The proposed model rather demonstrates a scenario-based analysis by using a representative grid data. SMUD does not take any responsibility for the results generated by this methodology.

Table of Contents

Abstract.....	ii
Acknowledgements.....	iv
Introduction.....	1
Chapter 1: Policy Entrepreneurship in California.....	3
1.1 Introduction.....	8
1.2 Regulatory Environment in California.....	12
1.3 Methodology.....	12
1.3.1 Theoretical Framework: Multiple Streams.....	14
1.3.2 Data Gathering.....	16
1.4 Discussion: Multiple Streams of VGI.....	17
1.4.1 Problem Stream.....	20
1.4.2 Political Stream.....	23
1.4.3 Policy Stream.....	29
1.5 Conclusions.....	29
1.5.1 Conclusions on the Use of MS.....	29
1.5.2 Policy Making in the Area of VGI.....	30
Chapter 2: Developing Strategies for Vehicle-Grid Integration.....	35
2.1 Introduction.....	35
2.2 Technical Background on VGI.....	36
2.3 Methodology.....	41
2.4 Analysis.....	43
2.4.1 Dynamic Pricing for PEVs.....	46
2.4.2 Demand Response for PEVs.....	48
2.4.3 PEVs as Energy Storage.....	52
2.5 Conclusions.....	54
Chapter 3: Quantifying the Economic Value of Vehicle-Grid Integration.....	59
3.1 Introduction.....	59
3.2 Literature Review.....	61
3.3 System Design & Methodology.....	67
3.3.1 System Inputs.....	69

3.3.2 Load Management Scenarios.....	76
3.3.3 PEV Consumers' Optimization Problem.....	77
3.4 Results.....	78
3.4.1 PEV Impacts on Electricity Demand.....	79
3.4.2 PEV Impacts on Distribution System.....	83
3.4.3 Economic Assessment of VGI.....	85
3.5 Conclusions.....	89
Conclusions & Future Work.....	94

INTRODUCTION

The issue of electric vehicle (EV) to smart grid integration has gained significant attention within the scientific literature, especially over the last decade. Researchers from the engineering and policy fields investigated grid impacts of EVs, and technical and market feasibility of various load management mechanism for EV charging. In late 2010, the interest addressed by scientific studies finally began to be applied in practice. In California, as the first wave of EVs—Nissan Leaf and Chevy Volt—entered into the mass market, policy makers started to see this development as an opportunity for transforming both transportation and electricity sectors through integrating clean electricity generation with clean mobility. Since then, the need for this transformation has only grown because of the State’s recent goals to reduce air pollution and oil consumption significantly by 2030 (Greenbalt, 2015).

The EV-smart grid integration, or as it is called *vehicle-grid integration* (VGI) in California, is a broad concept with implications for EV charger technology, electricity policy, load integration strategies, and ancillary grid services. Specifically, VGI refers to the “process” of taking several actions for improving the grid’s reliability, economic efficiency and environmental impacts through demand-side management of EVs. As it is mentioned in the California Independent System Operator’s VGI Roadmap (CAISO, 2013), the ultimate goal of VGI is enabling EV-based grid services. Developing a comprehensive understanding of VGI requires some level of background related to several topics. These topics include; (1) energy policy making such as utility regulation proceedings, (2) major grid operations such as energy services and ancillary grid services, (3) demand-side management (DSM) mechanisms such as demand response programs, and, finally, (4) DSM-enabling technologies such as utility metering and telemetry systems. Detailed descriptions of these topics will be provided in the following

chapters.

In this dissertation, I investigated various aspects of VGI starting from the on-going policy developments in California. My interest in VGI developed during the first year of my PhD program. In the summer of 2011, I participated in a focus group meeting where a participant from the East Coast told his story about how his whole neighborhood experienced a black out because of his EV charging. After listening to this story, I had a growing interest to investigate the scale of this problem, not only related to the distribution system but to grid operations overall. First, I started my investigations by attending VGI Roadmap workshops in Sacramento in 2013, where I had a chance to get to know the VGI stakeholders, and listen to major policy discussions. Second, I designed a survey study and conducted VGI stakeholder interviews in which I met representatives of major stakeholder organizations in person. The qualitative data gathered from these interviews are analyzed under Chapter 1 and Chapter 2. I started my investigation with analyzing qualitative data related to policy process to understand how the policy process for VGI has been formed, and has been effective in addressing problems.

At this stage, I faced the challenges of using political science theory for the first time in my research, and, for the first time, coding and clustering qualitative data. However, the great support from my research mentors at the Institute of Transportation Studies helped me develop necessary skills and background to perform these tasks. Finally, in Chapter 3, I switched gears back to my original academic background, and I used engineering methods to address my research questions. Overall, this process has been a very rewarding and a truly inter-disciplinary experience where I had a chance to investigate a socio-technical, complex issue through the lenses of both social science and engineering.

In Chapter 1, I performed a policy process analysis regarding VGI by using a descriptive model called Multiple Streams (MS) framework (Kingdon, 1995). This model was originally introduced in 1984 by the American political scientist John W. Kingdon (1984) from the University of Michigan. Kingdon aimed to describe the common patterns of federal policy making in the US, and conducted numerous survey interviews with federal employees including presidential staff, political appointees and career bureaucrats, and representatives of interest groups from the health care and transportation sectors. This framework provided relatively simple language—compared to other policy models/theories—that is accessible to researchers of interdisciplinary backgrounds. In my VGI analysis, I adopted Kingdon’s MS framework on a state-level energy policy issue using a set of VGI stakeholder interviews. The stakeholder interviews were conducted between March 2013 and April 2014 and include representatives of 18 organizations from the government, electricity, and PEV sectors. The stakeholders have addressed the questions as to why their organizations have been participating in VGI efforts, whether they advocate a particular technology or policy framework, and their experiences with consumer engagement in VGI. Following the MS framework, the qualitative data from the interviews are categorized under so-called *problem, political, and policy streams*. These three streams represent three independent processes that transform a policy alternative into an actual policy.

In Chapter 2, I first identify potential VGI strategies as considered by the stakeholders in California, then, provide a feasibility assessment for these strategies focusing on technical and market challenges. VGI strategies presented in this study included three major components; (1) identification of PEV load, (2) developing PEV load management mechanisms, and (3) deployment of enabling technologies. This study especially focused on the load management

strategies to address the questions related to how PEVs on the grid should be tracked, communicated, managed, and compensated considering their potential benefits to the grid system.

In Chapter 3, I developed a stochastic methodology for quantifying the technical and economical impacts of VGI. The most basic form of load management, dynamic pricing, is considered in evaluating the impact of the PEV load on various hourly electricity demand curves and distribution networks. The proposed model is demonstrated in the Sacramento Region, where a mid-size utility company currently provides dynamic pricing programs for PEV consumers. In this model, I considered a widespread PEV adoption scenario where 60,000 PEVs are deployed in the region, and all of these PEVs are used as commuter vehicles during the weekdays only. The analysis in Chapter 3 aims to help stakeholders to evaluate grid capacity constraints on handling widespread PEV adoption, and the effectiveness of load management mechanisms.

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CHAPTER 1:

INTEGRATING PLUG-IN ELECTRIC VEHICLES INTO THE GRID: POLICY

ENTREPRENEURSHIP IN CALIFORNIA

1.1 INTRODUCTION

Numerous studies have illustrated that plug-in electric vehicles (PEVs) present efficiency and environmental advantages over gasoline vehicles. According to the International Energy Agency (IEA, 2010), if annual PEV sales increase rapidly and reach 50% of new light-duty vehicle (LDV) sales by 2050, such a fleet will result in an approximate 30% reduction of CO₂ emissions from LDVs globally. In another study by Axsen et al. (2011), researchers found if 1 million light-duty PEVs are deployed in California, PEVs will decrease LDV-related greenhouse gas (GHG) emissions by more than 33%. Such environmental benefits, combined with the increasing interest in energy independence, led elected officials to several PEV-related policy actions in California, where the transportation sector contributes the highest fraction of GHG emissions, 37% (CARB, 2014). These PEV-related policy actions included: providing financial incentives for PEV purchases and infrastructure (e.g. Assembly Bill 118, 2007); developing rules for utility companies to support PEV deployment on the grid (Kehoe, 2009); and, eventually, targeting the deployment of 1.5 million ZEVs in the state by 2025 (Executive Order B16-2012 [GOV, 2012]).

Most of these policy efforts target the “PEV readiness” of the vehicle market and the grid infrastructure. A classification of major issues associated with PEV readiness is presented in Figure 1.1. Efforts toward market readiness have dealt with issues such as increasing consumer education, mitigating the high up-front cost of PEV ownership, and advancing PEV inventory.

On the other hand, efforts toward infrastructure readiness have emphasized deploying PEV chargers and integrating PEVs into the grid system by developing load management strategies, and enabling *PEV-based grid services* in which PEVs can support the reliable and efficient operation of the grid. Besides such advantages, if not managed, large increases in PEV use may require additional electricity generation capacity, and overload distribution transformers, depending on the regional infrastructure. Therefore, since early 2009, energy-related state agencies in California started to look for appropriate technology and policy frameworks for this issue, considering the technical complexities of the highly regulated electricity sector.

This study focuses on the policy developments in California related to PEV-grid integration or, in short, vehicle-grid integration (VGI). Focusing on the formation of the policy process between 2009 and 2014, this research addresses the questions of how the policy process has been initiated, who the participants are, and what are the challenges related to policy-making in the area of VGI. California has been chosen as the case study due to the state's influential role and experience in promoting PEVs, and as the holder of one of the largest LDV markets in the world. The findings provide lessons for other states or regional governments who are considering similar policy actions related to VGI.

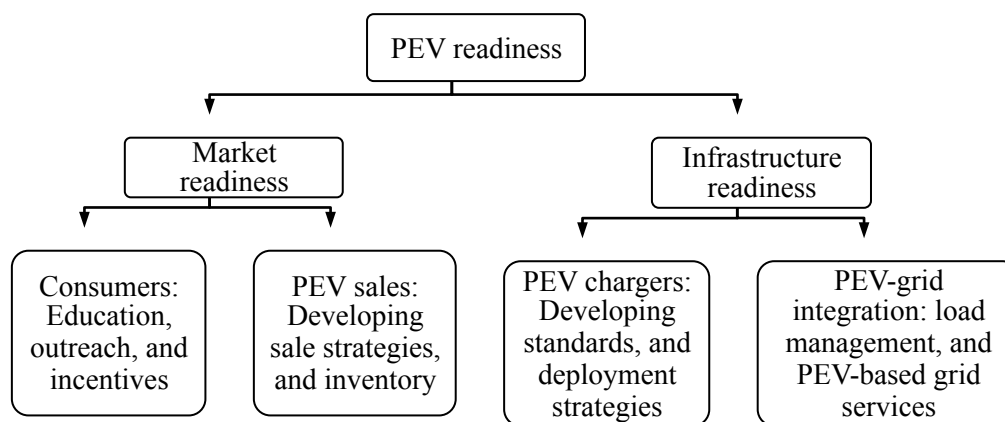


Figure 1.1: A classification of major topics under the PEV readiness

A theoretical framework, Multiple Streams (Kingdon, 1995) has been used in the analysis of the qualitative data from stakeholder interviews. Parallel to the focus of this study, the framework focuses on the agenda setting and policy formation *stages* rather than implementation and outcomes. It also provides relatively simple language—compared to other policy models/theories—that is accessible to researchers of interdisciplinary backgrounds. The stakeholder interviews were conducted between March 2013 and April 2014 and include representatives of 18 organizations from the government, electricity and PEV sectors. The stakeholders have addressed the questions on why their organizations have been participating in VGI efforts, whether they advocate a particular technology or policy framework, and their experiences with consumer engagement in VGI. Following the MS framework, the qualitative data from the interviews are categorized under so-called *problem, political and policy streams*. These three streams represent three independent processes, which transform a policy alternative into an actual policy.

The following section (Section 1.2) provides a critical background on the stakeholders who actively participated in regulatory process for VGI in California. Section 1.3 describes the methodology of gathering data from VGI stakeholder interviews, as well as the major MS framework concepts used in this research. The MS framework is applied in Section 1.4 to evaluate three major forces in the policy formation; problem, politics, and policy. Finally, Section 1.5 includes conclusions of the results under two topics. The first part is related to the conclusions on the use of the MS framework for this particular case. The second part features conclusions and lessons related to policy-making in the area of VGI.

1.2 REGULATORY ENVIRONMENT IN CALIFORNIA

The regulatory environment related to VGI includes a broad range of stakeholders as it impacts both the transportation and electricity sectors. These stakeholders include participants of the policy process from inside and outside of the government. The participants from inside the government include major energy planning and regulation agencies, the governor's office, and state legislatures who advocate the deployment of PEVs. Participants from outside the government include electric utility companies, automakers, PEV service providers, and research and advocacy groups. The following paragraphs provide a brief background on these stakeholders, particularly government agencies, and their interests in VGI.

In California, the State's electricity grid is largely operated by the California Independent System Operator (CAISO) and the Western Electricity Coordinating Council (WECC). WECC is responsible for the coordination of system operators at the higher, regional level, whereas CAISO's primary responsibilities are balancing electricity generation and consumption by operating wholesale electricity markets and programs, and managing high-level transmission congestion. This organization operates both the energy market and the ancillary services market, which are both relevant to VGI. Along with power generators, customers who can provide demand response and energy storage to the system are identified as *resources* and are compensated as much as they participate in the relevant market programs.

Ancillary grid services in CAISO include frequency regulation and reserve markets. An imbalance between demand and supply can create frequency fluctuations on the grid. The resources that can provide supply or demand based on the automated generation (AGC) signals from CAISO help to stabilize the grid frequency. This service is traditionally done by power stations that can operate fast enough and have the ability to operate their electric machines as both generator and motor. On the other hand, the resources that can generate electricity in a very

short amount of time can be used to correct the error between forecast demand and actual supply. If managed, PEVs can be used in both demand response and energy storage resources, where they can provide frequency regulation or reserve services in a more economic way. These aspects of the PEVs made CAISO a very important and active stakeholder in VGI issues. Besides CAISO, there are several other balancing authorities in California, which make up about 20% of the system, including the two largest publicly-owned utilities (POUs) and some agricultural districts (CAISO, 2015).

POUs and investor-owned utilities (IOUs) are other important players in the electricity sector. In California, there are 35 publicly-owned utilities (POUs) operating to provide approximately 25% of the State's electricity (CMUA, 2003). The Los Angeles Department of Water and Power (LADWP) and the Sacramento Municipal Utility District (SMUD) are the largest POUs. On the other hand, the largest IOU is Pacific Gas and Electric (PG&E), which serves a population of approximately 15 million, mostly within Northern California (PG&E, 2015). The other IOUs are San Diego Gas and Electric (SDG&E), and Southern California Edison (SCE). Most of these large-scale utility companies are interested in PEVs, and operate PEV-related electric transportation departments that work on VGI issues. There have been different channels of communication where utility and automaker companies found opportunities to interact with each other. During the stakeholder interviews, these channels of communication were mentioned as CPUC's AFV proceeding workshops, VGI roadmap workshops, PEV Collaborative of California, and Electric Power Research Institute's infrastructure working council.

Figure 1.2 presents the major stakeholders and organizational interactions in California related to VGI. The participants are categorized into three layers: (1) policy/regulation, (2) whole

electricity market/service, and (3) consumption. The policy and regulation layer includes policy-makers in the electricity and transportation sectors. These policy-makers have a complex relationship with the utilities, automakers and consumers. They can influence or impact the regulatory process in different ways. Among the electricity regulators, the California Public Utilities Commission (CPUC) is the primary regulatory agency for the IOUs. CPUC's main responsibility is protecting public interest against the private entities that manage public utilities such as water, electricity, and communication. This agency has the authority to introduce very detailed and narrow regulations on the utilities. These regulations are called CPUC proceedings or "order instituting rulemakings," which may include several phases and decisions. The CPUC proceedings may be related to CPUC's usual responsibilities such as electricity rate adjustments or to addressing the tasks given by legislative authorities. The VGI-related proceedings under alternative fueled vehicle (AFV) program are categorized as quasi-legislative proceedings by CPUC. These policy actions will be discussed in Section 1.4.3 in detail.

California Air Resources Board (CARB) and California Energy Commission (CEC) are other important actors in both the electricity and transportation sectors. CEC is the state's primary energy planning agency. Besides conducting energy research, CEC provides policy suggestions, regulates siting of power plants, and administers the State's research and development funding on alternative transportation technologies. On the other hand, CARB has a very broad jurisdiction over the organizations whose operations directly impact air quality and GHG. These organizations include automakers and power generators. CARB is currently not an active stakeholder in VGI process as the VGI-related goals initially target utility-level issues.

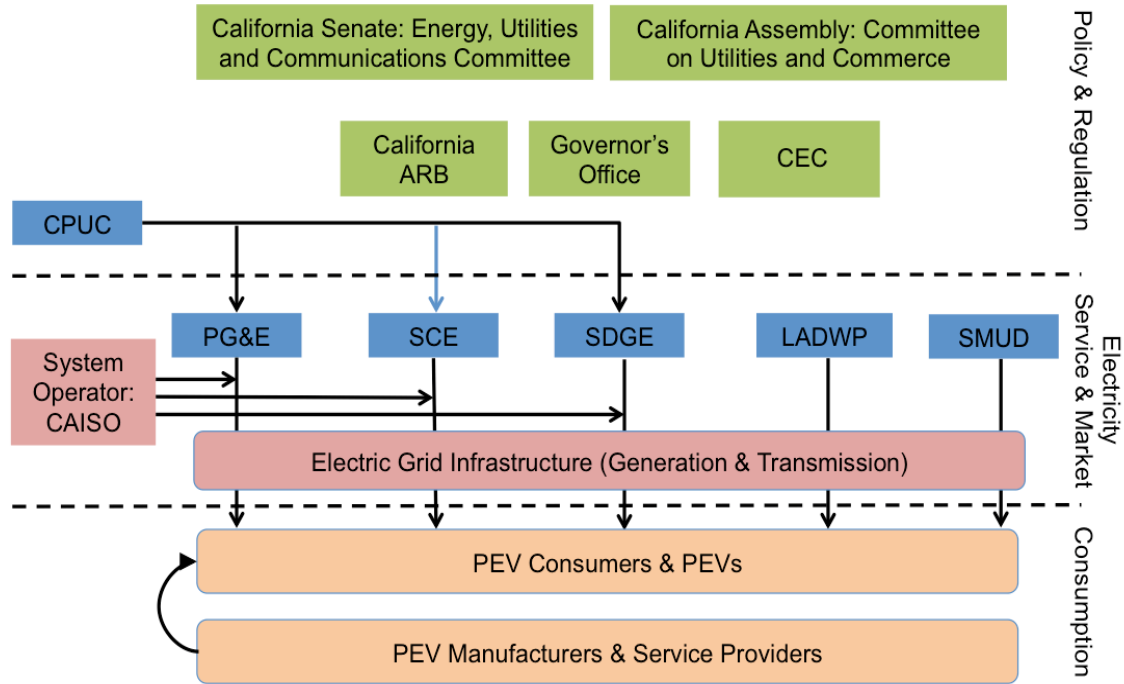


Figure 1.2: The illustration of the major organizational interactions for VGI in California

1.3. METHODOLOGY

1.3.1 Theoretical Framework: Multiple Streams

The Multiple Streams (MS) framework was proposed by American political scientist John Kingdon in 1995 to describe agenda setting and the formation of public policies involving participants from inside and outside the government (Kingdon, 1995). The main premise of this framework is that policy changes may occur when advantageous developments from so-called *problem, political and policy* streams converge into a “policy window.” The MS framework suggests that decision makers sometimes fail to define their goals clearly and do not always set satisfactory levels of achievement for these goals. Rather, public policies are typically formed under conditions of ambiguity and semi-random developments (Zahariadis, 2007). Therefore, models of rational decision-making do not accurately describe the reality in public policies (Kingdon, 1995).

Within the MS Framework, the *problem stream* relates to how an issue becomes a concern that motivates policy makers to take action. Several mechanisms that bring problems to the attention of policy makers are presented, including indicators such as data driven reports and expert opinions, focusing events, and feedback channels through which policy makers follow outcomes of a current program (e.g. media). The *political stream* is composed of several elements such as national mood, public opinion, organized political forces, and judicial activities within the government. Lastly, the *policy stream* is conceptualized as a “primeval soup” in which ideas float around, confront one another, and in some cases, merge (Kingdon, 1995). In this stream, some ideas (or policy proposals) float to the top of the policy agenda and others fall to the bottom based on two major criteria; technical feasibility and value acceptability. In this competitive process, Kingdon (1995) discusses the role of policy communities and entrepreneurs. Policy entrepreneurs are the participants who are willing to invest resources in the hope of a future return.

When the problem, political, and policy streams join, they temporarily create advantageous opportunities for policymaking called *policy windows*. When a window opens, policy entrepreneurs sense their opportunity and try to attach their solutions to the problem. This attachment is known as *coupling* in the MS framework. In contrast to problem-solving models—in which people become aware of a problem and consider alternative solutions—the MS framework suggests that solutions *float around in and near government*, searching for problems with which to be coupled, or searching for political events that could increase their likelihood of adoption (Kingdon, 1995, pp172).

The MS framework has been used in several studies related to energy and environment. In addition to the use of the framework, some scientists have tested the theory for their specific

cases and provided contributions. For instance, Storch and Winkel (2013) analyzed forestry policy developments in some regions of Germany drawing from the MS framework. The authors found that the concept of coupling in MS fits very well in the case of policy entrepreneurs in Germany who have already prepared solutions and wait for policy windows in order to attach their proposals. Collantes (2006) has adopted the MS framework to conduct an analysis of the origin of the ZEV mandate by CARB between 1990 and 2004. Based on the findings, the author suggests that the problem, political, and policy streams were largely *interdependent*, as opposed to being largely independent as the MS suggested. In the case of the ZEV mandate, elected officials and political appointees have been in close collaboration with state bureaucrats prior to opening a policy window. In another study, Brunner (2008) has adopted MS framework to analyze the policy formation of emissions trading in Germany. The author found that the influence of multi-level governance structures, learning processes, and networks are not sufficiently considered by the theory. This conclusion suggests that the researchers who use the MS framework should consider the additional evaluation of these issues, as they may have an impact on the policy formation and decision-making processes.

1.3.2 Data Gathering

The on-going policy developments in VGI show that policy-makers have been able to successfully create a channel of communication between utilities and automakers—two fields that were historically largely independent from one another. By conducting stakeholder interviews, I aimed to gain a deep understanding of the roles different organizations played in the formation stage of the policy process, and what major barriers exist toward achieving their individual goals. During the semi-structured interviews, stakeholders were asked questions related to four major topics; (1) the motivation of their organizations in participating or

advocating VGI; (2) their preferences regarding technology and policy framework; (3) their relations with other stakeholders; (4) and lastly, their visions on consumer engagement. In addition to the use of qualitative data from stakeholders, the analysis is supported by VGI-related official documents published by the government agencies such as the Governor's Office, CPUC, and CAISO.

The PEV-grid stakeholder interviews were conducted between March 2013 and June 2014. The interview participants are representatives of various stakeholder organizations from the public policy, utility, and PEV sectors. The PEV sector consists of representatives from original equipment manufacturers (OEMs), and PEV supply equipment (EVSE) companies. The interview invitations were sent to a sample of 20 organizations that were active participants in the VGI roadmap workshops. As seen in Table 1.1, the participants included organizations from the five largest utilities in California, five policy makers, and eight companies from the PEV sector. Twelve of the 18 interviews were conducted in-person at the participants' workplaces. The rest of the interviews were conducted by phone. The participants are full-time employees who hold administrative or senior staff positions in a PEV-related department or working group.

Table 1.1: The stakeholders that participated in VGI stakeholder interviews

	STAKEHOLDER ORGANIZATION	DATE
1	CAISO	03.21.13
2	San Diego Gas & Electric (SDGE)	03.25.13
3	Southern California Edison (SCE)	03.25.13
4	Sacramento Municipality Utility District	04.03.13
5	ChargePoint	04.04.13
6	Pacific Gas and Electric (PG&E)	04.05.13
7	Nissan North America	04.08.13
8	AeroVironment	04.10.13
9	Ford	04.12.13
10	Los Angeles Department of Water and Power	04.18.13
11	ECotality	04.25.13
12	California Public Utilities Commission	11.20.13
13	Electric Auto Association	12.10.13
14	Former Senator Christine Kehoe	12.20.13
15	GM/OnStar Alliance	01.08.14
16	California Energy Commission	04.24.14
17	California Governor's Office	04.30.14
18	BMW North America	06.11.14

The data used in this analysis has limitations in terms of covering a limited number of stakeholders in VGI. For instance, the spectrum of the participants extends to energy researchers, consultants, demand response companies, and some clean technology companies who are interested in developing innovative solutions in the area of VGI. Additionally, more automakers are becoming interested in PEV-grid issues as they have plans to deliver PEVs in the future. These stakeholders are not included in the survey because of the limited time of the researchers. Additionally, the analysis features qualitative data from stakeholders that represent expert opinions. These expert opinions are based on the interviewee's perceptions and limited knowledge. Therefore, the data may not necessarily represent a complete picture about the involvement of the stakeholder organizations in the policy process.

1.4 DISCUSSION: MULTIPLE STREAMS OF VGI

This section provides an analysis of the qualitative data gathered from stakeholder interviews and VGI-related official documents such as CPUC proceedings, the Governor's ZEV action plan, and VGI roadmap. The stakeholder interview data is categorized into the three-stream format as suggested by the MS. The problem stream addresses the question of which problem(s) are target for stakeholders, and how VGI came into their agenda. The political stream addresses the question of how elected officials were involved in the policy-process, and whether they sensed the public mood and interacted with organized political forces or pressure groups. Finally, policy stream introduces the actors in the policy community, actions by the policy entrepreneur, and addresses how the policy solutions were related to the problems. The analysis is solely based on the qualitative data from stakeholder interviews. This data represents interviewee's private opinions based on their experience within the relevant stakeholder organization.

1.4.1 Problem stream

The VGI stakeholders, especially policy-makers, highlighted several reasons that motivated them to engage with VGI. These reasons – or from the MS framework's problem-solving perspective, these *problems* – are categorized under three: (1) concerns over limited grid infrastructure, (2) growing need for ancillary grid services, and, lastly, (3) need for improving economics of PEV ownership. Although, different stakeholders prioritized and framed their motivations differently, these three issues have been highlighted frequently in both, stakeholder interviews and government documents such as CPUC whitepapers on AFVs. On the other hand, there have not been any focusing events such as large-scale grid failures related to PEV charging or other types of urgency that suddenly forced stakeholders' attention to this issue.

The first problem is the limited infrastructure to facilitate widespread adoption of PEVs.

The impact of the PEV load on the grid infrastructure has been highlighted in two ways; overloading distribution transformers and increasing annual peak demand, (which typically happens in mid-July). Importantly, policy-makers were unanimous that the grid infrastructure is vulnerable to system failures when a large amount of load is added to the system or sudden changes occur in the load patterns. On the other hand, different utilities expressed different opinions about how much the PEV load will affect their systems. This issue appears to be highly dependent on the characteristics of the utilities' individual infrastructure and their generation mix. Specifically, two utilities, SMUD and SDGE, expressed upgrades in the distribution system would be necessary in the case of widespread PEV adoption. The SDGE representative reported that so far they have experienced one transformer failure in a commercial area where several PEVs were being charged at the same time. These PEVs were being operated under a car-sharing program. The SMUD representative mentioned that the residential areas with single-unit households are most likely to be impacted by PEVs if those PEVs are clustered in specific neighborhoods and charged with high-levels of power. This situation seems to be different in highly urban areas. The LADWP representative mentioned that multi-dwelling units in urban areas are less likely to be impacted as they receive power through transformers with larger capacity. PEVs in these areas are also more likely to use shared charging platforms, which can be easier managed by the utility.

According to the most recent PEV load impact analysis provided by the IOUs (CPUC, 2014), the total cumulative PEV ownership in the IOU region is estimated at 97,350 PEVs, an increase of 56,150 PEVs from 2013. For such increase, the total cost for PEV-related infrastructure upgrades in 2014 was reported as \$1,771,686. This cost only includes distribution system equipment upgrades such as neighborhood transformers and secondary line conductors

and connectors. The CPUC representative mentioned that this amount is not a significant cost considering IOUs' operation budget. Nevertheless, it is very difficult to predict the future impact considering widespread PEV adoption scenarios. Estimating future impacts of the PEV load requires a highly stochastic assessment of future PEV locations, PEV owners' charging behavior, and energy needs. At this early stage of the market, all of the utility representatives agreed that notification of PEV ownership by their customers is highly important for tracking the PEV load that will be added on their distribution system.

The VGI's prospects for grid services were mentioned as the second-most important motivation behind the VGI activities. The CAISO representative mentioned that PEV-based grid services fit perfectly into California's vision of the future grid with, "*a lot of distributed resources and renewables (interview).*" Such potential makes some stakeholders very optimistic about the future of VGI. Especially private entities have a growing interest in being the major service provider for VGI through providing communication or load management services for grid operators. As the representative from ChargePoint, the largest PEV charging network operator, asserted, "*charging car[s] should be free, because the benefit to the grid is higher than the cost of it (interview).*" The interviewee added, "*we think that EV-based demand response is going to be a big business in the future (interview).*" In this regard, the issue of PEV and residential photovoltaics (PVs) integration also earns attention from utility companies. Some utilities mentioned that the electricity generated by residential PVs can create technical difficulties on the distribution system such as voltage sags and so-called *backfeeding* problems (interview). Therefore, consumers can also value managed charging, "*to get the best out of their solar panels (interview),*" if they have PVs on their roof.

Finally, the need to improve the economics of PEV ownership is mentioned as another

challenge where VGI can provide solutions. This need became more significant after the Governor's Brown ZEV initiative in 2012. Based on the IOU estimates, Figure 1.3 represents the existing cumulative PEV adoptions between 2012 and 2014, and IOU estimations up to 2022 (CPUC, 2014). Achieving PEV deployment goals requires very high consumer adoption rates. Although, this aspect of VGI was not discussed by the majority of the stakeholders, policy-makers envision VGI as an innovative way to improve the economics of PEV ownership. For instance, participant from Governor's Office stated that *"if we can figure that out and understand what the benefits are, and tie them back to the consumer, this will also help to drive PEV adoption -- it creates another value stream to incentivize EV ownership (interview)."* In this regard, policy-makers envision that monetary returns from VGI can overcome barriers related to the high upfront cost of PEV ownership, even at the stages of market launch. In contrast to the previously mentioned issues, which are long-term target areas, the vision to create additional value for consumers falls under near-term target areas.

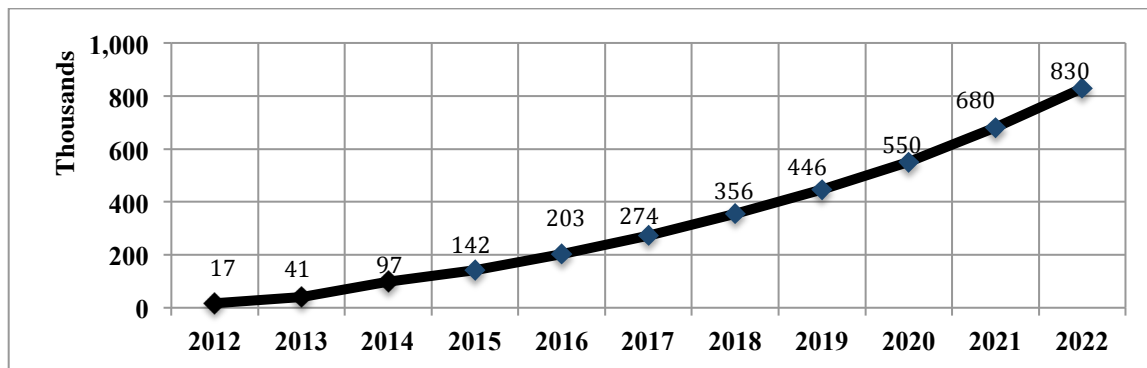


Figure 1.3. Actual (2012-2014) and estimated numbers of PEVs in California until 2022

1.4.2 Political stream

In the MS framework, the political stream entails involvement of politicians, and some important developments related to changes in public mood, pressure group campaigns, ideological distributions in congress, and administration. In the case of VGI, the impact of public

mood and partisan politics was very low, and has not been an important factor that shaped the policy process. On the other hand, legislative actions have played a very important role. The policy window for VGI regulations was opened largely by two major legislative actions, i.e. Senate Bill 626 and Governor Brown's ZEV initiative. These legislations did not include any technical solutions. They rather set the agenda on VGI for energy-related regulatory agencies in California. Specifically, SB626 gave CPUC the authority to implement regulations on enabling PEV load management systems and PEV-based grid services. The following analysis describes the limited but critical involvement of political actors in VGI.

The first utility-oriented PEV policy initiatives in the legislation began in the State Senate with Senate Bill 626 (Kehoe, 2009). The bill was introduced by former San Diego Senator Christine Kehoe to the senate in February 2009, and was supported by the majority of both the senate and assembly members (supported 85% in senate and 77% in assembly). SB626 directed CPUC to adopt policies *to develop infrastructure sufficient to overcome any barriers to the widespread deployment PEVs* (Kehoe, 2009). In stakeholder interviews, Kehoe described her general interest in PEVs and the electricity sector as being members of various energy and environment-related committees in the senate. She stated that she wanted to, *"keep pushing electric cars,"* and, she thinks, *"it is a great idea for California (interview)."* According to Kehoe, SB626 was not controversial enough to receive coverage by national and local media. She also did not face any serious opposition from other elected officials. She claims:

"I don't remember a single conversation with another senator who told me they will vote 'no' ...[in] some cases, some politicians think climate change is not a serious threat, others say that if it is a serious threat, the market should come up with solutions...But we

didn't have any formal opposition on this bill. Utilities didn't say, 'We cannot manage this bill' (interview)."

In detail, SB626 directed CPUC to adopt rules and perform some important assessments to address several issues such as: (1) the electrical infrastructure upgrades necessary for widespread use of PEVs, (2) the impact of PEVs on grid stability and the integration of renewable energy resources, and (3) the impact of widespread use of PEVs on achieving the State's GHG emission reduction goals and renewables portfolio standard program. This bill is supported by CPUC, some PEV advocate groups, and also some major PEV manufacturers such as Nissan, Toyota, and Tesla. In response to SB626, CPUC reactivated its Alternative Fuel Vehicle (AFV) proceedings, which were originally founded to support CARB's zero emission vehicle (ZEV) mandate policy in the early 1990s. CPUC's policy actions to address SB626 will be discussed in the following section.

In March 2012, there was another development in the political stream that supported the policy window opened by SB626. California Governor, Jerry Brown, introduced the goal to deploy 1.5million ZEVs as an executive order (Executive Order B16-2012). This legislation set several milestones toward the deployment of 1.5 million ZEVs in California by the year 2025 (GOV, 2012). These milestones in the executive order include the order that "electric vehicle charging will be integrated into the electricity grid." Following the executive order, specialists in the Governor's Office prepared an action plan that required CEC, CPUC, and CAISO's collaboration to develop a VGI roadmap plan for California (GOV, 2013). These state agencies formed a policy community called *VGI working group* (interview). The VGI working group organized three stakeholder workshops between October 2012 and October 2013. Collaborating with these workshops, CAISO released a VGI roadmap in December 2013. This roadmap

suggested policy-makers focus on developing solutions under three inter-dependent tracks; (1) determining VGI value, (2) developing enabling policy, and (3) supporting enabling technology (CAISO, 2013). From SB626 to the VGI roadmap, Table-2 presents a summary of the VGI related policy and market developments in California between 2009 and 2013. Although, the term of *VGI* has not been used in government papers until 2013, the CPUC's AFV regulations from 2010 and 2011 were the first policy actions to address VGI.

Table 1.2: VGI related policy and market developments

Policy and Market Developments	Organization	Date
California Senate Bill 626 is introduced	CA Senate	October, 2009
Alternative Fuel Vehicle Proceedings on VGI started	CPUC	August, 2010
First wave PEVs arrived: Chevy Volt and Nissan Leaf sales began	GM and Nissan	December, 2010
Governor Brown's ZEV initiative is announced	Governor's Office	March, 2012
ZEV Action Plan is released	Governor's Office	September, 2012
VGI Roadmap workshops started	Vehicle-Grid Working Group	October, 2012
Vehicle-Grid Integration Roadmap is released	CAISO	December, 2013

1.4.3 Policy stream

The policy stream represents the stage where elected officials leave problem-solving in the hands of specialists. In this stage, career bureaucrats and specialists have a highly influential role and they often work as a community, called the *policy community* in MS. Here, alternatives are being developed, and solutions are being presented to the decision-makers by the so-called *policy entrepreneurs*.

In CPUC, regulations are usually proposed by specific divisions based on their areas of expertise, then presented to a CPUC commissioner who leads the commission on that particular

topic. In the case of VGI, the Energy Division Staff at CPUC has been the policy entrepreneur by preparing the CPUC’s policy proposals on VGI. During this process, CPUC collaborated with other state agencies such as CEC and CAISO. In this analysis, this collaborative group of bureaucrats is represented as a policy community specializing in VGI.

The major developments and issues discussed in Section 1.1.4 are summarized in the following figure (Figure 1.4). This analytical representation provides a basic scheme, solely based on the concepts from MS framework. On the other hand, it does not represent possible complex relationships between problem, politics, and policy streams. In Figure 1.4, the policy solution, R.09-08-009, refers to the first rulemaking in the area of VGI, which is introduced by CPUC in August 2010. This rulemaking described major issues that needs to be addressed by CPUC but did not release the final regulations (decision D11-07-029) until July 2011. The content of D11-07-029 will be discussed in the following paragraphs.

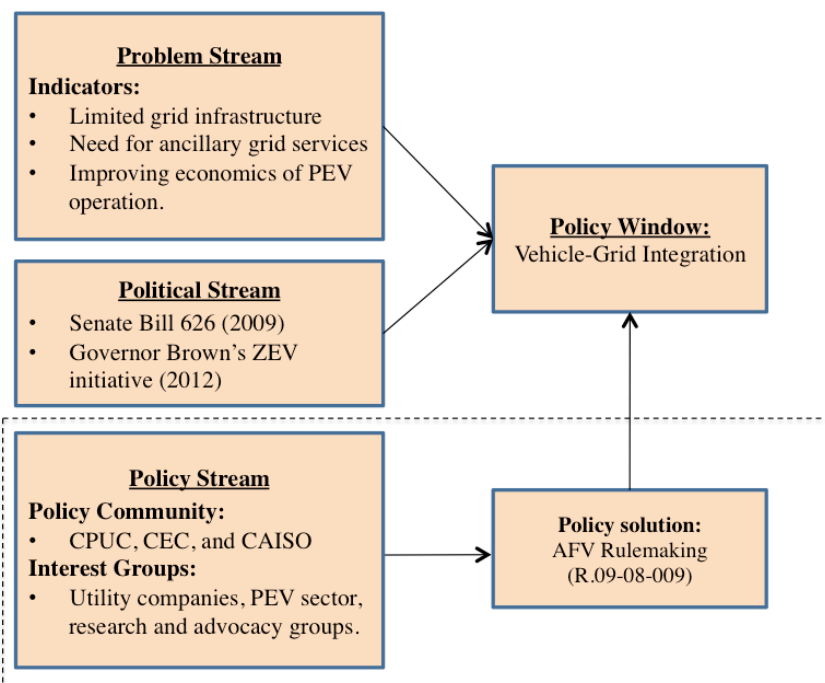


Figure 1.4. Conceptual representation of MS framework applied to VGI.

When it was introduced in 2009, SB626 provided a framework for how CPUC should

develop PEV-related utility regulations. CPUC has been directed to collaborate with CEC, CARB, air quality management districts, utility and OEMs *to evaluate and implement policies to promote the development of equipment and infrastructure for the use of low-emission vehicles* (SB626, 2009). According to the MS, policy entrepreneurs sense when a policy window will be opened and start developing their ideas prior to the windows of opportunities. Consistent with this premise, the issue of VGI had been on the CPUC's agenda prior to arrival of SB626. The Commission started a proceeding on this topic about two months before the governor signed SB626 in October 2009.

In response to SB626, CPUC initiated the first rulemaking on VGI in August 2010, which resulted in VGI regulations (decision D11-07-029). The content of this decision was prepared by the Energy Division Staff of CPUC collaborating through six stakeholder workshops organized between September 2010 and February 2011. Besides the IOUs, there were some organizations that actively participated in the rulemaking discussions. These organizations included SMUD, GM, EVSP Coalition, and some environmental research and advocacy groups such as Natural Resources Defense Council, Green Power Institute, Environmental Coalition, and Clean Energy. Through this decision, regulators introduced specific rules as well as some general expectations of CPUC from the IOUs regarding several important VGI issues. The content of D.11-07-029 introduced PEV rate design principles and enforced research on the growing PEV load, tracking infrastructure upgrade costs associated with PEVs, and developing innovative PEV metering and load management strategies. Table 1.3 presents the content of D.11-07-029 as it relates to VGI. In the following paragraphs, the major target areas of these policy actions and their effectiveness on addressing the problems will be evaluated.

Table 1.3: Content of the VGI regulations under alternative-fueled vehicle proceedings by CPUC

Decision D.11-07-029 Content	Major Goals
Utility Notifications	Developing utility notification systems related to the location of new PEV purchases (mostly through automakers and dealerships).
Load Research and Cost Tracking	Tracking growing PEV load on the grid, and infrastructure maintenance and upgrade costs associated with this PEV charging.
PEV Metering	Identifying PEV metering options, and developing a sub metering protocol for metering PEV load through non-utility devices.
DR and Load Management	Developing innovative load management strategies, and demonstrating new technologies in small-scale projects.
PEV Rate Design principles	Introducing special rates for different PEV metering configurations to keep PEV operation competitive to the conventional LDVs.
Utility Cost Recovery	Sharing PEV-related utility cost of infrastructure upgrades to all rate payers
Consumer Education & Outreach	Educating consumers on cost effective PEV charging, and potential uses of PEV battery in grid services.

One of the major goals that VGI regulation targeted is enforcing VGI-related research and demonstrations to the IOUs. Each technology option for VGI may bring several risks to the utility-level grid operations. For instance, using a separate electricity meter for PEVs through the PEV supply equipment risks liability issues regarding customer billing. Enabling PEV-grid communication risks data security, and lastly, bidirectional power flow brings technical difficulties on the distribution system. Most importantly, failures in the management of these technologies may damage consumer satisfaction on both PEV ownership and the utility service. Therefore, most of the stakeholders agree that introducing such a new technology to the grid system can be difficult, especially if the stakeholders do not know what the actual economic value from that technology will be. In this regard, utilities may not be willing to directly engage

with VGI. This concern has been mentioned by the CPUC representative through the following statement;

“[In VGI] their [the utilities’] first reaction is going to be skeptical, because their first reaction is going to be, ‘Reliability is our number-one concern. We are willing to do new things, but we will not risk our grid reliability. What you are saying has some potential risks over reliability. We are nervous about that, we first need to do a lot of testing’ (interview).”

A similar opinion is expressed by the CEC representative, *“utilities are not known for innovation. They are known for consistency and lack of change... because they need to deal with the consequences (interview).”* To overcome this problem, CPUC introduced several regulations that enforce IOUs to conduct VGI research and development activities such as providing an annual research report on the PEV load in their territories and conducting demonstration and pilot projects on DSM and PEV metering. These research and development activities help CPUC to circumvent information asymmetry between utilities and policy makers so that policy makers can understand how the growing PEV load on the grid impacts the distribution system, can consider potential solutions for each utility region, and can ascertain the potential economic value from PEV-based grid services. The results and reports from VGI demonstration and pilot projects by the IOUs create a feedback channel for CPUC to continue their incremental policy-making with a better understanding of the technical feasibility and economic value of VGI.

Additionally, VGI regulation targeted to provide financial protection and educational support for PEV consumers. D.11-07-029 enforced utilities to provide consumer education and outreach about PEV charging. The same regulation also provided financial protection to PEV buyers from high electricity rates and the cost of upgrading distribution infrastructure due to

PEV load. The cost of infrastructure upgrades by the utility will be accepted as a shared cost to all ratepayers until the end of 2016.

Overall, CPUC's regulations emphasized research, and created an environment where stakeholders try new solutions through demonstration and pilot projects. However, the rules brought by D.11-07-029 did not effectively address all of the SB626 objectives. For instance, the key concerns, such as how a growing PEV load on the grid should be managed and what kind of technologies should be used, are not addressed completely. Considering the early phase of the PEV market and smart grid applications, the agency adopted an incremental policy-making strategy on VGI. Several issues are being carried over into the upcoming AFV proceedings.

During the regulatory process, the agency has faced two major barriers in policy-making; (1) the complexities involved in quantifying economic value from VGI; and (2) the feasibility concerns about adopting VGI enabling technologies on the grid. Feasibility concerns exist because adopting a new metering or communication technology in the grid system requires high reliability standards. On the other hand, these enabling technologies including PEV metering, PEV-grid communications, and bidirectional PEV chargers are still being evaluated by the automakers and electricity industry.

Secondly, the difficulties to quantify economic value from VGI are mentioned by several policy-makers. The economic assessment of a particular VGI solution requires high amounts of data from a regional grid system and deals with uncertainties related to future conditions of the PEV and electricity markets and PEV consumer behavior. Due to these complexities, stakeholders, especially policy-makers, are having difficulty understanding the economic value of VGI. Consequently, investing resources for policy-making becomes difficult. For instance, the interviewee from CPUC stated, *"we have to do a lot more research on that (to determine*

economic value)... I don't know how we can create policies in this space without understanding what the value is (interview)." Additionally, the participant from the Governor's Office highlighted the importance of quantifying the value of VGI for different stakeholders including consumers: *"if you talk to stakeholders, some folks are interested what the value is...If I am an EV buyer, what do I get out of it as a customer? This question can be understood in 2-3 years (interview)."*

1.5 CONCLUSIONS

1.5.1 Conclusions on the use of MS

The framework provided a systematic approach on investigating the policy process for VGI in California. It has been observed that the three streams of policy formation exist in this state-level energy policy issue. Additionally, the framework's emphasis on agenda setting and policy formation can provide important insights for other government organizations that are interested in initiating similar policies. However, there were also some disadvantages of using the MS framework. Some premises of the framework did not fit within the case study, as some aspects of the policy-making have not been captured in the model.

Most importantly, MS framework's description of the "coupling" process did not accurately capture the policy-making in VGI. MS assumes that solutions *float around in and near government*, searching for problems to which to be coupled (Kingdon, 1995, pp172). Such generalization in decision-making may suit sudden policy changes but may not be applied to cases in which policies target long-term energy planning issues. In these cases, the solutions may not be instantaneously available because of the technical complexities or unknown market conditions. Regarding VGI regulations, CPUC specialists did not give a prompt response when the policy window was opened by SB626 in October 2009. The first set of decisions was

introduced in July 2011, after the agency's involvement with stakeholder workshops to understand the technical and economic complexities from different perspectives. As observed in the case of VGI, the incremental aspect of policy-making in energy and environmental issues may be very significant.

As suggested by Gormley (1986), dynamics of the policy process may be different based on the so-called *issue areas*. The regulatory politics may vary systematically based on two main characteristics of an issue: public salience (or public attention) and the technical complexity. Following this premise, the MS framework can be expanded in a way that the narrative includes two cases of policy formation where the policy solution is ready, or not ready. As the MS framework only assumes instantaneous availability of the solutions, it does not provide a space for discussions of technical or market challenges on addressing a problem where a final solution is not ready. Such technical challenges can be related to several issues such as; (1) information asymmetry between the stakeholders, (2) technology constraints, or (3) past regulations that create limitations and need to be changed. Future steps of this study will investigate these aspects of the policy process to provide potential contributions regarding policy-making in energy-related sectors.

1.5.2 Policy-Making in the Area of VGI

Concerns over the limited grid infrastructure, growing needs for ancillary grid services, and improving the economics of PEV ownership led elected officials to take policy actions in the area of VGI. A policy window was opened for the first time through SB626 in 2009, and later, supported by the Governor's ZEV action plan in 2012. These developments brought VGI into the agenda of a policy community that works on electricity and transportation-related energy planning issues. Empirical findings show that the Energy Division Staff in CPUC has been a

policy entrepreneur among the participants of the policy process by introducing VGI-related regulations for the IOUs.

Considering technical barriers, the agency initiated an incremental policy-making strategy, in which policies aim to address the three major problems previously mentioned in 5.1. CPUC's VGI regulations emphasized research, created an environment where stakeholders can discuss and try new solutions, and identified major issues that stakeholders should consider in the long-term. However, the rules brought by D.11-07-029 did not effectively address all of the SB626 objectives. Several important issues have been carried over into the upcoming AFV proceedings. The empirical evidence suggests that two largest barriers facing an effective policy solution have been (1) the complexities involved in quantifying economic value from VGI; and (2) the feasibility concerns about adopting VGI enabling technologies on the grid.

The findings from this analysis may have implications in policy-making. First, the results show that policy-makers should focus on developing methodologies to quantify economic value from VGI solutions, perhaps, *before* investing resources into demonstration and pilot projects. Such methodologies should consider regional characteristics of the grid operations, and uncertainties in the LDV and electricity markets. Each utility's region should be evaluated individually, considering unique characteristics of infrastructure, grid operations, and consumer profiles. Later on, policy-makers can integrate these individual assessments to evaluate VGI from a bottom-up approach to see the State-level impacts.

Secondly, stakeholders are currently in the phase of evaluating feasibility of various load management technologies from different perspectives such as data privacy, billing liability, and impacts on battery life. These evaluations are mostly being done through demonstration projects managed by the utility companies. However, the existing model where utilities propose and

manage these demonstration projects may not be an effective solution. As mentioned by several stakeholders, utilities currently do not have any significant incentive to develop innovative and cost-effective solutions for VGI. On the other hand, utilities, being risk-averse organizations, may diminish the potential benefits in their VGI assessments. This situation may result in the inefficient use of funding resources and, even, block the progress toward innovative strategies toward VGI. Alternatively, these VGI-related assessments can be performed by the third party research organizations closely collaborating with the utilities on issues such as data gathering, hardware installations and communicating with PEV consumers when necessary.

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CHAPTER 2:

DEVELOPING STRATEGIES FOR PLUG-IN ELECTRIC VEHICLE AND SMART GRID INTEGRATION IN CALIFORNIA: A QUALITATIVE ANALYSIS OF EXPERT OPINIONS

2.1 INTRODUCTION

Deployment of plug-in electric vehicles (PEVs) presents several benefits to the transportation economy and environmental sustainability. According to a group of energy regulators in California (Governor's Office, 2013) these benefits can be classified into the following five categories: (1) decreasing cost of transportation fuel, (2) improving air quality – locally and globally, (3) increasing energy independence, (4) supporting the clean technology sector, and, finally, (5) supporting the electricity grid through PEV-based grid services. Among these benefits, supporting the electricity grid is becoming an important issue due to rapid increase in renewables. Especially in California, the share of renewables is expected to reach 50% of the electricity generation mix by 2030 (Olson et al., 2015). The amount of electricity generated by renewables can be hard to predict based on environmental conditions. This situation brings challenges in grid operations. The uncertainties caused by renewables make the grid vulnerable to large imbalances between demand and supply, and, therefore, higher frequency and voltage spikes. These challenges motivate energy planners in California to consider PEV-based grid services, which have significant potentials for integrating renewables, improving grid reliability and, also, mitigating negative impacts of the growing PEV load on the grid infrastructure (Ryan and Lavin, 2015).

Enabling PEV-based grid services, on the other hand, requires developing appropriate technology and policy frameworks, known as *vehicle-grid integration* (VGI). Our previous study

(Chapter-1) showed that the feasibility of incorporating VGI enabling technologies into the grid has been one of the major barriers in policy-making in California. This empirical study first identifies potential VGI strategies as considered by the stakeholders in California, then, provides a feasibility assessment for these strategies focusing on technical and market challenges. VGI strategies presented in this study included four major components; (1) identification of PEV load, (2) choosing a load management strategy, (3) deployment of enabling technologies, and, finally, (4) providing grid services and compensating participants. This study especially focused on the load management strategies to address the questions related to how PEVs on the grid should be tracked, communicated, managed, and compensated based on their benefits to the grid system.

The analysis is performed based on a set of qualitative data from VGI stakeholder interviews. These interviews were conducted between March 2013 and June 2014, including representatives of 18 organizations from the government, electric utility, and PEV sectors. The organizations in California are chosen because of the State's experience in developing VGI technologies and policies. The participants evaluated feasibility issues associated with potential VGI strategies based on personal or company experiences. The stakeholder opinions are compared and contrasted for issues on which they were divided.

The following section provides the necessary technical background on major grid operations, smart grid and VGI. The methodology for data gathering and analysis is described in detail in Section 2.3. In Section 2.4, the qualitative data is analyzed under three categories of demand side management, which include dynamic pricing, demand response, and energy storage. Finally, findings from the analysis are summarized in Section 2.5.

2.2 TECHNICAL BACKGROUND ON VGI

Recent developments in information technologies led grid operators toward the vision of a *smarter grid* system where intelligent and prompt control systems are implemented over the complex grid infrastructure enabling reliable, cleaner, and efficient electricity delivery. These communication and control systems have different implications at the electricity supply and demand sides. Figure 2.1 presents some key components of the smart grid, including generation, transmission, and distribution systems with end-users including industrial, commercial and residential customers. Among the components shown in Figure 2.1, the system operator, also called the independent system operator (ISO) has a critical role in balancing demand and supply through direct regulations or various market measures. Utility companies are mostly responsible to deliver electricity through their distribution infrastructure. The distribution infrastructure includes substations and distribution transformers, which provide a safe way of power delivery to customers from high or medium-voltage electricity lines. For residential areas, distribution transformers are usually called neighborhood transformers. Note that, in Figure 2.1, the cylinder-looking neighborhood transformers are located on the poles presented in the distribution system.

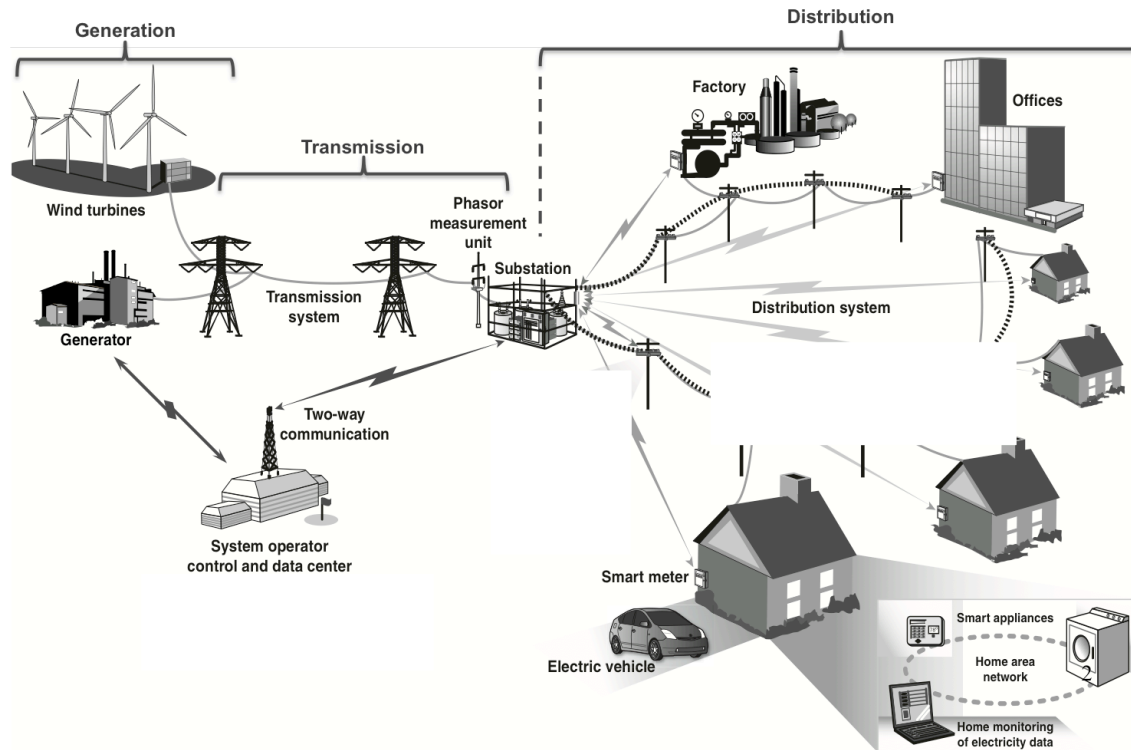


Figure 2.1: Illustration of a smart grid system (as adapted from GOA, 2011).

On a smart grid, the emerging technologies enable consumer control of electricity consumption. For instance, new telemetry technologies are being used to communicate with consumers and encourage them to adjust their consumption during critical times. Such applications on the grid bring prospects toward advancing *demand-side management* (DSM) programs in order to improve better utilization of the generation assets, and prevent increases in peak electricity demand. In particular, preventing increases in peak electricity demand is very important for stakeholders in the electricity sector as they plan the generation, and transmission infrastructure based on the peak demand—often occurring during summer heat storms in California.

Recently, DSM is becoming more important due to increased renewable electricity generation, especially from solar and wind-based generation (Williams et al., 2012). The electricity generation through renewables can be hard to predict based on environmental

conditions. Such situations create high uncertainty in the system. Additionally, distributed generation such as residential PVs can create technical difficulties in the distribution system such as voltage sags and so-called backfeeding problems (Lewis, 2011). Figure 2.2 shows several hourly load curves for the California ISO (or CAISO) between the years 2012 through 2020. These curves are based on future estimates in the demand and electricity generation mix, and represent a load profile for an average day in CAISO territory. Net load is the difference between forecasted load and expected electricity production from renewables. As seen on Figure 2.2, these curves produce steep reductions in the mid-afternoon that quickly ramps up to produce an “arch” in the evening. These conditions on the grid system create needs for new resources with specific operational capabilities. For instance, these resources need to have short and steep ramp capability in the case when CAISO must start or shut down generation resources in order to meet an increasing or decreasing electricity demand over a short period of time. In this regard, some DSM strategies present potential low-cost solutions that meet the required operational flexibility described above.

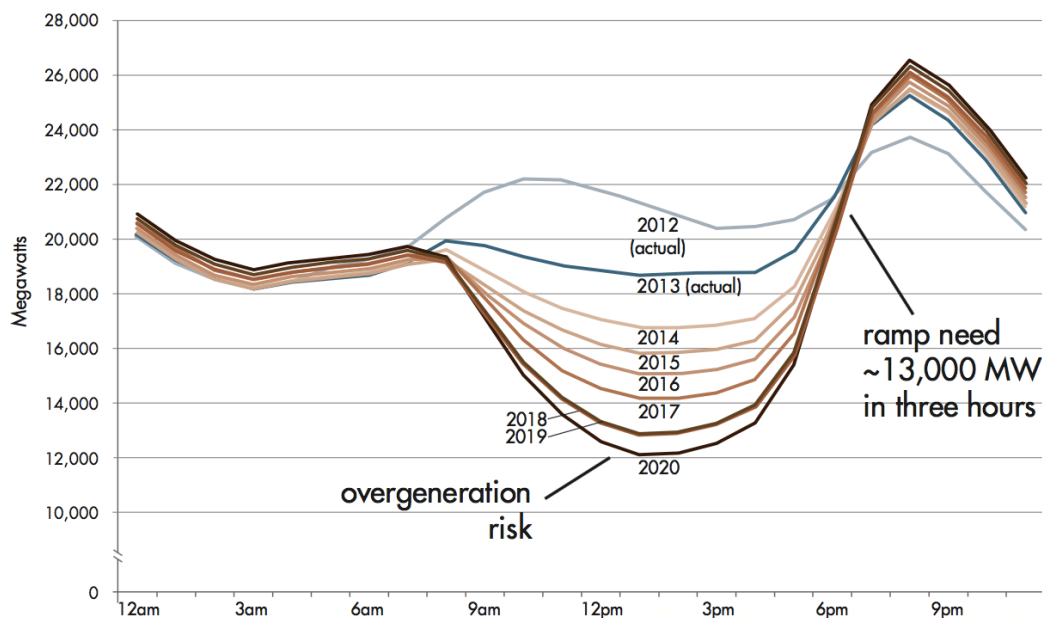


Figure 2.2 The estimated net load curves for a spring day (March 31), which show steep ramping needs and overgeneration risk after increased renewable generation in CAISO territory (CAISO, 2013)

The DSM strategies discussed in this paper include energy storage systems (ESS), demand response programs, and, most basically, dynamic pricing programs such as time-of-use (TOU) and real-time pricing (RTP) rates. TOU rates follow a fixed schedule of prices that vary by time of the day and season. The rates reflect historical patterns of daily demand. RTP is a variable price per kWh that reflects real-time changes in the wholesale market price of electricity. The dynamic pricing programs target long-term changes in consumer behavior, however, they may not provide urgent load curtailment solutions during critical periods such as peaking generation capacity and transmission capacity. In such emergency cases, demand response programs and ESS can provide solutions for the load curtailment.

In demand response programs, usually administrated by independent system operators or utilities, electricity consumers (traditionally large-industrial customers) participate through so-called *direct-load control* (DLC) programs. DLC refers to demand response programs in which the participant's consumption is temporarily limited by an automated management system during a demand response request (Leo et al., 2012). Due to these arrangements, DLC-based demand response programs require telemetry devices and official agreements between program participants and the program providers.

In California, the grid system operator, CAISO, manages DR programs, in which participants can enroll and receive compensation based on several performance measures, including the amount of electricity they curtail during a DR request. Based on CAISO terminology, DR and ESS *resources* can ramp-up or ramp-down the net load curve and can provide energy and/or ancillary services to the grid. Therefore, these resources can participate in wholesale markets, which include real-time and day-ahead markets. The ancillary grid services market includes reserve and frequency regulation markets. This scope of market measures

(energy, reserves, and frequency regulation) target minimizing the gap between supply and demand optimally in real-time (also called load balancing). Resources that provide ancillary grid services need to operate faster, and in some cases, be automated directly by the system operator. In this regard, demand response and ESS are considered low-cost and reliable options for ancillary grid services.

The market measures described above provide incentives for utilities to participate in load balancing as well. Through a mix of the DSM programs (e.g. dynamic-pricing, DR, or ESS), utilities may buy electricity at a lower cost during off-peak hours, protect their infrastructure from overloads, and be compensated by their system operator if they participate in CAISO-level DR programs. Recently, utility-administrated residential DR is becoming popular for the air conditioning load, especially during summer heat waves (Mathieu et al., 2015). Utilities limit the use of air conditioners through a device installed in participants' homes, and participants are compensated by annual bill credits as a financial incentive.

The DSM strategies described above such as dynamic pricing, demand response, and energy storage can be applied to PEVs. In the following sections, these load management strategies will be evaluated for PEVs from technical and market feasibility perspectives. The technical feasibility assessment will include PEV metering, telemetry, and the use of bidirectional chargers (BC), which enable two-way (bidirectional) power flow between PEV battery and the grid. The market feasibility assessment will include limitations and concerns from the perspectives of consumers and the wholesale electricity market.

2.3 METHODOLOGY

The data for this empirical study is collected through stakeholder interviews. These interviews were conducted between March 2013 and June 2014. As seen in Table 2.1, the

participants are the representatives of various stakeholder organizations from the utility and PEV sectors. The interview invitations were sent to a sample of 20 organizations that were active participants in the VGI roadmap workshops. Table 2.1 provides a list of participants from policy, utility and PEV sectors. The PEV sector consists of representatives from original equipment manufacturers (OEMs), PEV supply equipment (EVSE), and service provider (EVSP) companies. Twelve of the 18 interviews were conducted in-person at the participants' workplaces. The rest of the interviews were conducted by phone. The participants are full-time employees who hold administrative or senior staff positions in a PEV-related department or working group.

Table 2.1: The stakeholders that participated in VGI stakeholder interviews

	STAKEHOLDER ORGANIZATION	DATE
1	California Independent System Operator	03.21.13
2	San Diego Gas & Electric (SDGE)	03.25.13
3	Southern California Edison (SCE)	03.25.13
4	Sacramento Municipality Utility District	04.03.13
5	ChargePoint	04.04.13
6	Pacific Gas and Electric (PG&E)	04.05.13
7	Nissan North America	04.08.13
8	AeroVironment	04.10.13
9	Ford	04.12.13
10	Los Angeles Department of Water and Power	04.18.13
11	ECOtality	04.25.13
12	California Public Utilities Commission	11.20.13
13	Sacramento EV Buyers Association	12.10.13
14	Former Senator Christine Kehoe	12.20.13
15	GM/OnStar Alliance	01.08.14
16	California Energy Commission	04.24.14
17	Governor's Office	04.30.14
18	BMW North America	06.11.14

During the semi-structured interviews, stakeholders were asked questions related to four major topics; (1) their perception of the technical and economic value of VGI; (2) their preferences regarding technology and policy framework; (3) their relations with other stakeholders; (4) and lastly, their visions on consumer engagement. The participants evaluated

feasibility issues associated with potential VGI strategies based on personal or company experiences. The qualitative data is coded as key VGI technologies such as PEV metering, submetering and telemetry, and load management concepts such as TOU rates, RTP, and DLC.

This study presents qualitative data as the expert opinions to develop a basis for understanding current and future issues related to feasibility assessment for VGI. As discussed by Dennis et al. (2014), a feasibility assessment for a technology or project may include several measures such as technical feasibility, economic feasibility, market or marketing feasibility, resource feasibility and operational feasibility. These feasibility measures may exist in different levels based on the topic that is being evaluated. In the case of VGI, stakeholders mostly focused on the technical and market challenges. Therefore, the feasibility assessment in this study focused on the identification of technical and market feasibility issues as the primary target areas.

The use of stakeholder interviews as expert opinions is discussed by several studies in the literature. For instance, Hirschey (2008) discussed that the opinions of experts carry a lot of weight in many professions, if they consist of unbiased and informed opinions. On the other hand, Knudson and Morrion (2002) presented the weaknesses of using expert opinions in empirical research. The authors discussed that the expert opinions are subjective and they may conflict and often change about key points of an issue. Additionally, the stakeholder organizations are usually also interest groups, especially in the area of energy policy. Therefore, the survey participants may express opinions that carry some level of their personal or company interest. These aspects of the expert opinions are considered as the major limitations in this study.

2.4 ANALYSIS

This section provides a feasibility assessment for VGI strategies based on the qualitative data collected from stakeholder interviews. The stakeholders mostly discussed four major stages regarding VGI. These stages are conceptually presented in Figure 2.3. As seen on the figure, the first stage for VGI is identified as the PEV load identification. By the identification of PEV load, stakeholders can understand the potential for VGI. This is currently being done by so-called utility notifications (CPUC, 2010a). Utility representatives work with automakers and consulting companies to gather location-specific PEV ownership data in their territories (interview). After understanding the VGI potential, interested parties need to set specific goals for the types and amount of PEV-based grid services that they can utilize through PEV load management strategies. The second stage of VGI is the design of a particular PEV load management strategy that will incentivize consumer participation. The PEV load management strategy can be based on one or more of the DSM programs such as dynamic pricing, demand response, or energy storage. This stage requires complicated system assessments to evaluate proposed load management programs that can be implemented, considering market realities. Through these assessments, stakeholders can compare the potential load management programs based on the technical feasibility and economic value, and make decisions on the execution before spending resources on enabling technology and marketing.

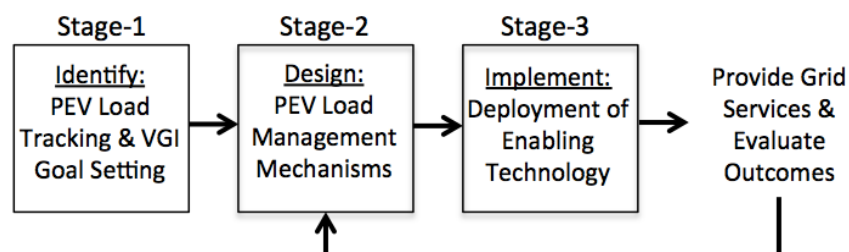


Figure 2.3: Conceptual representation of four-major stages involved in VGI

The third and fourth stages of VGI involve the execution of the chosen PEV load management strategy. The enabling technology, such as a communication infrastructure, should be provided to PEV owners and the participants of the load management such as PEV buyers, utilities or service providers who manage the PEV telemetry, should be compensated by the electricity market mechanisms. Finally, by evaluating outcomes of the adopted PEV load management strategy, stakeholders can understand the successes and failures, and consider changes in the design of their load management strategy.

The following analysis identifies major VGI-related technical and market challenges, which decision-makers should consider in their feasibility assessments. As discussed in Section 2.2, the major load management strategies for PEVs are identified as (1) dynamic pricing, (2) demand response, and (3) energy storage. Each load management strategy should address the questions such as how the PEV load should be identified/included, communicated, managed, and compensated. As also discussed in Section 2.2, some load management strategies may be considered differently. Table 2.2 presents a list of load management strategies currently being implemented or evaluated by the stakeholders in California. In the following paragraphs, each of the strategies will be evaluated from technical and market-feasibility perspectives based on the expert opinions gathered from the survey data.

Table 2.2: PEV load management strategies considered by stakeholders in California

PEV Load Management	Description
Dynamic pricing: PEV Household-TOU	Special TOU rates for those households who own a PEV. This program has higher on-peak rates and lower off-peak rates compare to regular rates.
Dynamic pricing: PEV-TOU	Special TOU rates, for the PEV charging only, which have higher on-peak rates and lower off-peak rates compare to previous program (PEV Household-TOU).

Dynamic pricing: PEV-RTP	RTP rates, for the PEV charging only, where price signals represent the real-time changes in the wholesale electricity prices and/or renewable electricity generation.
Demand Response: Direct Load Control (DLC)	Demand response programs where PEV load is aggregated, and being monitored and managed by a 3 rd party agent who participates in a DR program managed by the utility or system operator.
Energy Storage: Vehicle-to-Grid (V2G)	PEV battery represents an ESS that can be used for load shifting, residential PV integration, and a back-up power by the household.
Energy Storage: Vehicle-to-Home (V2H)	PEV battery represents an ESS that can sell power back to the grid when PEV owner participates in an ESS program managed by the utility or ISO.

2.4.1 Dynamic Pricing for PEVs

Stakeholders, especially utility representatives, discussed dynamic pricing strategies as the most basic form of load management strategy for PEVs. Utilities in particular have experience adopting TOU rates for PEV owner households (PEV Household-TOU). This strategy is already implemented by the five largest electric utilities in California. Through these programs, the households owning a PEV can enroll in a special electricity rate program, which typically has cheaper electricity rates during off-peak demand hours and higher prices during on-peak demand hours. The timing and amount of PEV household TOU rates change seasonally. Among the PEV household TOU rate options in California, the cheapest rates were provided by LADWP as 6 cents/kWh for winter off-peak, while most expensive rates were provided by PGE as 37 cents/kWh for the super-peak hours in summer (interview). This pricing scheme shows that the cost of PEV charging can be six times more expensive in California based on the location and time that a PEV is being charged.

Through the PEV household TOU rates, utility representatives were agreement that they receive satisfactory behavioral change from consumers. For instance, an SDGE representative mentioned, *“For now, TOU prices (are) good enough; eighty percent of charging happens at*

night (interview)”. Such an outcome is very favorable for the utilities because these programs do not require a separate utility meter or a particular grid communication system to be implemented. By using existing smart meters, utilities can provide a special TOU rate for households that own a PEV. On the other hand, these utilities also currently provide another dynamic pricing option for PEV consumers, where a separate utility meter is installed in the PEV owner’s house for billing PEV charging only (also called “PEV metering”). Through this separate smart meter, utilities can provide PEV-only TOU rates. Although these rates are usually more complicated as compared to the PEV household TOU rates, they better represent daily patterns of the wholesale electricity market.

There are two types of configurations that can be applied to the additional PEV meter (CPUC, 2010b). The first configuration is called a series meter, which is installed under the same electricity panel and on the same electricity line where household smart meter is connected. This option is cheaper as compared to a parallel configuration where a meter is installed onto a separate electricity panel. However, the cheaper series configuration requires more complicated data management. In general, there was a concern that the use PEV-only dynamic pricing may not be convenient for consumers due to the additional cost paid to the supplementary smart meter, panel upgrades, labor and permits. The cost of installing a separate utility meter was estimated at \$2,000, according to the ChargePoint representative (interview). Stakeholders also consider use of customer-owned submeter for billing PEV load. This customer-owned submeter can be located in the EVSE or in PEV itself. On the other hand, such a system requires electricity regulators to develop standards and procedures, where the 3rd party (submeter manufacturer) will be responsible for certification, accounting, and billing data produced by their submeter (CPUC, 2012). A utility representative voiced his concerns on the reliability and compliance issues of

using non-utility metering for billing purposes (interview). This issue is currently a policy discussion in the CPUC's AFV agenda. A roadmap for adapting PEVSP was released in Jan 2012 (CPUC, 2012).

Utilities currently do not offer RTP rates for the PEV consumers. The utilities agreed that the RTP rates might be difficult for the consumers to follow, with the exception of the workplace charging (interview). At the time of the interview, SDGE started their workplace RTP program where the prices reflect the day-ahead electricity market (interview). The SDGE's workplace pilot program includes 35 workplace charging station located in the utility campus.

2.4.2 Demand Response for PEVs

Dynamic pricing programs target long-term behavioral changes in the ways that PEV buyers charge their cars, however, these programs do not provide solutions for urgent grid issues such as real-time balancing of supply and demand. Grid services that are being used for real-time balancing of supply and demand are becoming more important with the rapid increase of renewable electricity generation. Advanced load management options, such as demand response and energy storage, are being considered to allow PEVs participate in major grid services. As discussed in Section 2.2, demand response programs can be designed for PEVs in the form of direct load control (DLC) where a third-party agent manages a group of PEVs collaborating with the utility or CAISO. In this regard, stakeholders mostly discussed the implementation of a telemetry system for DLC, which will allow PEV-grid communication and PEV charge control. PEV-grid communications refer to the PEV charging systems where a two-way data communication exists between PEV buyer and utility (or a third party company on behalf of the grid operators).

Enabling communication between PEV and grid systems is a major technical challenge that raises data management issues similar to PEV metering. On the other hand, it is critical to build a telemetry system to integrate PEVs with other smart grid systems. If enabled, the PEV-grid communications can be used in the management of PEV load, aggregated or individually, to provide energy, non-spinning reserves, and frequency regulation services. Currently, there are several communication technologies available for PEV-grid applications including cellular networks, satellites, power line carriers, and household WiFi. OEMs and EVSE companies may adapt one of these technologies to connect PEVs into their network. When it comes to manage PEV charging, OEM representatives expressed their concerns about an EVSE-based communication system. From an OEM perspective, the EVSE involvement in PEV-grid communication is an “*intervention*” because PEVs are already equipped with the cellular network (interview).

Additionally, EVSEs may not provide advanced charging algorithms since they cannot receive signals from PEVs regarding the battery’s state of charge. On the other hand, EVSE-based communications provide some advantages in the shared charging environment, such as public charging and workplace charging, where the EVSE can provide spatial data regarding the locations of PEV load (interview). From a utility’s perspective, whether communication solutions are provided by EVSE or OEM does not matter—it is all about the cost, “*whichever provides the cheapest option—that one is better (interview).*” Representatives from PG&E and SMUD seemed to be very interested in working with communication providers to learn about the cost of adapting a particular infrastructure and data management system. Related to this topic, the ChargePoint representative estimated that they pay about \$10/year per charger for the cellular

connection installed in their 15,000 PEV charge stations (interview). He added that the cost of \$10/year is very sensitive to the amount of data being used by a particular charger.

Representatives from both utility and automaker companies mentioned Electric Power Research Institute (EPRI)'s effort to create a so-called *open integration platform* for PEVs. EPRI leads a group called Infrastructure Working Council, which includes 8 automakers and 15 large-scale utilities across the US (EPRI, 2014). Utilities agreed that standardization among the PEV manufacturers would be helpful in accelerating VGI (interview). On the other hand, current regulations in the state of California do not allow the adoption of mobile systems (such as cars) for the use of load metering and utility billing (CPUC, 2012). Stakeholders first need to wait for the Division of Measurement Standards (under California Department of Food and Agriculture) to develop procedures for certifying mobile meters. Once this is accomplished, stakeholders need to address how these mobile submitters will be associated to the master (household) meters, and be managed when the PEVs are being charged in a different utility jurisdiction.

Besides the technical challenges mentioned above, stakeholders also discussed several market challenges related to the PEV participation in demand response. These market challenges exist on both sides—consumers and the wholesale electricity market. In the wholesale market, CAISO DR, called proxy demand resources, participants should provide load curtailment at the minimum 100 kW for the energy market and 500 kW for the non-spinning reserve market (CAISO). Smaller loads that are aggregated to meet the minimum requirements should be located in one of the 24 CAISO-defined areas, which do not include SMUD and LADWP territories. Besides the location and minimum load requirements, DR participants above 10 MW are required to have a telemetry system in compliance with NERC standards. This amount would correspond to a fleet of 3030 PEVs, considering a level-II (at 3.3 kW) charging scenario.

Considering these telemetry and location requirements, a CAISO representative postulated that the existing DR program by CAISO might be difficult to adopt for PEVs in the near-term.

Additionally, representatives from PGE and CPUC mentioned that the regulation market in CAISO is relatively small and may not be attractive for PEVs. Although, PEVs can be a low-cost solution, PEV consumers, especially those who own a small battery, may not receive significant revenue from the regulation market. As a CPUC representative mentioned, *“if you have 100,000 EVs, they will saturate the frequency regulation market—the price will be zero (interview).”* This observation is supported by a scientific study Leo et al (2012). The researchers found that there is a negligible revenue opportunity for aggregators and end consumers, totaling only \$8 per PEV annually, considering a high PEV adoption scenario in California. In contrast to the case in California, some stakeholders discussed that market conditions for the grid services vary among regions. Therefore, frequency regulation may have a potential value for different regions in the US, especially some regions on the East Coast (interview).

Finally, the issue of consumer engagement has been discussed. Most of the stakeholders mentioned that they have had very limited experience so far when it comes to consumer engagement. The initial thought about the potential consumer profile is that environmentally motivated consumers are most likely to participate if they have large battery capacity (interview). OEM representatives generally expressed a more consumer-focused approach toward VGI. He was concerned that PEV buyers may have difficulty understanding PEV-based grid services. As the GM/OnStar representative explains (interview):

“We are very much advocates of making sure the utilities have some of the fundamental relationship with the customers across the board. So it is very easy to say customers are

[going to] find out VGI activities, but the truth is that the market is struggling even explaining PEV-TOU rate options.”

OEM representatives also expressed their concerns over the DR programs with automated load control. For instance, one Nissan representative mentioned that they have “*a huge concern that somebody else having control on DR will effect [consumers’ PEV experience] negatively (interview).*” From an OEM perspective, it is either the consumer or the OEM that should be the one to control charging. In summary, OEMs expect that if grid operators engage with PEV-based grid services, they should make it simple for the PEV consumers, and “*do not over-control (interview).*”

Despite the technical and market challenges described above, demand response is a hot topic among the stakeholders. In particular, participants from utility and automaker companies discussed their demonstration and pilot projects on PEV demand response. For instance, representative from SCE described their pilot project in their workplace. They were planning to install 180 chargers in 17 facilities with the goal of evaluating DR potential. Additionally, SMUD representative mentioned SMUD’s interest in automated load control programs during the summer heat storms (interview). At the time of the interview, SMUD was starting a pilot program, where the utility limits the level of PEV charging during the critical peak hours in summer.

2.4.3 PEVs as Energy Storage Systems

Finally, stakeholders discussed the use of PEV battery as energy storage for the grid in the form of vehicle-to-grid (V2G) or vehicle-to-home (V2H), which is a more isolated way of using PEV battery to reduce total electricity demand. This advanced load management strategy requires dealing with several technical challenges in addition to the challenges described in

previous sections such as enabling PEV metering, telemetry, and wholesale market challenges. The use of PEV battery for energy storage requires adopting bidirectional chargers, which is a type of PEV charger that permits two-way power flow between the PEV battery and the grid (or only the building into which the PEV is plugged).

Related to the use of PEVs in energy storage, interviewees first discussed the technical feasibility of the use of bidirectional chargers (BCs). Several OEM representatives mentioned that long-term impacts of frequent charge/discharge of the battery are unknown. As the Nissan representative mentioned, they do not have enough experience to know how bidirectional charging affects battery chemistry, “*different battery chemistry lends itself to different behavior and degradation (interview)*”. Therefore, the representative from Nissan concluded, “*the battery warranty issue is a totally unknown area (interview)*.” Such ambiguity creates skepticism among the stakeholders about the future of PEV-based grid services that require BC technology.

Besides the concerns over battery, stakeholders also expressed concerns about the grid infrastructure. For instance, two utility representatives mentioned some technical limitations for V2G on the distribution side. These limitations include PEVs creating voltage sags and so-called *backfeeding* problems (interview). As utilities consider grid reliability as their primary responsibility, the participants from the utility sector mostly agreed that, “*V2G is a long time away,*” especially to be considered a widely available resource for the grid system (interview).

On the other hand, utilities were very interested to see consumers adopting vehicle-to-home (V2H) or vehicle-to-building (V2B) systems in their household or workplace. These systems require a complete isolation between PEVs and the grid when PEV is being used as a power resource. Therefore, these systems require a separate electric panel that is connected in parallel to the main electric panel that carries power from the utility. Despite the anticipated

high cost, some utility representatives suppose that consumers might be interested in V2H to use as back-up power or for better utilization of their solar panels (interview). Additionally, V2H does not require any agent to be involved since the PEV owner has complete control over the system.

Finally, stakeholders, especially policy-makers, discussed the use of V2G applications for vehicle fleets. A CAISO representative highlighted the V2G potential in fleets including trucks or busses with higher and more stationary batteries compared to light-duty vehicles. Consistent with this idea, CEC representatives mentioned that V2G could be of value on military campuses, where vehicles stay idle for long periods of time during the year (interview). Participants from CEC, CPUC and Aerovironment described a large-scale V2G demonstration project on two air force bases in Southern California (interview). The Los Angeles PEV and V2G demonstration project includes the first federal PEV fleet of 42 vehicles, which makes up 100% of the general-purpose fleet in that military base (Marnay et al., 2014). This demonstration project aims to utilize up to 700 kW of power capacity on the grid collaborating with SCE as the local utility company.

2.5 CONCLUSIONS

In this study, the industry experts from electricity and PEV sectors evaluated feasibility issues related to VGI strategies, focusing on technical and market challenges. The qualitative data is analyzed under three categories of demand side management strategies, which include dynamic pricing, demand response, and energy storage. Although, they are presented as completely separate strategies, some of these load management strategies can be implemented at the same time. For instance, at the time of the interview, SMUD were starting their VGI pilot program where they were experimenting feasibility of PEV-TOU rates and a DLC together in the

same program. Table 2.3 presents a summary of the technical and market challenges as discussed by the stakeholders.

As seen in Table 2.3, both, technical and market challenges, exist in each of the load management strategies, except providing special time-of-use rates for the PEV owner households (PEV household-TOU). This strategy is currently being implemented by all major utilities in California. The following three conclusions are some of the highlighted results from the qualitative analysis in Section 2.4:

- Stakeholders from utility and automaker sectors were highly skeptical about the near-term feasibility and economic value from V2G. Fleet vehicles have been mentioned as the only near-term application of such system;
- Financial prospects of VGI on grid operations created a competition between OEMs and EVSP companies over being the primary service provider for PEV metering and PEV-grid communications;
- OEM representatives expressed concerns over the consumer engagement with PEV-based grid services. They are concerned that the complicated VGI programs by the utilities, and control of PEV charging by third parties may impact consumer experience from PEVs negatively.

Table 2.3: A summary of technical and market feasibility issues as discussed by the VGI stakeholders

PEV Load Management Strategies	Technical Challenges	Market Challenges
Dynamic Pricing	<ul style="list-style-type: none"> • Separate utility meters are costly. • Submetering systems for PEVs currently cannot be used in utility billing. 	<ul style="list-style-type: none"> • Implementation of real-time rates can be difficult for consumers to follow.
Demand response: Direct Load Control (DLC)	<ul style="list-style-type: none"> • Managing telemetry between PEVs and the grid system brings additional cost and data liability issues. 	<ul style="list-style-type: none"> • DLC programs may limit consumers' control over the PEV charging, and have a negative impact on consumers' PEV experience.
Energy Storage	<ul style="list-style-type: none"> • The battery impacts of frequent charge and discharge are not totally understood. • The power from V2G creates reliability problems in the distribution system. • Installment of a separate electricity panel is costly. 	<ul style="list-style-type: none"> • The regulation market in CAISO currently does not have a significant potential for PEVs. • CAISO's telemetry and minimum load requirements will be difficult to apply on PEVs.

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CHAPTER 3:

QUANTIFYING THE ECONOMIC VALUE OF VEHICLE-GRID INTEGRATION: A CASE STUDY OF DYNAMIC PRICING IN THE SACRAMENTO MUNICIPAL UTILITY DISTRICT

3.1 INTRODUCTION

Since early 2009, energy planners in California have been considering vehicle-grid integration (VGI) as a potential solution for mitigating negative grid impacts of PEVs and renewables, and improving the economics of PEV adoption. Although these perceived benefits exist, our previous study (Chapter-1) showed that the PEV-grid stakeholders face difficulties in quantifying potential value from VGI. The complexities related to VGI modeling exist because of the limited available data in the early PEV market, and uncertainties related to consumer behavior, wholesale electricity markets, and utility grid operations. This situation creates a major barrier toward developing a policy framework for VGI.

Several methodologies have been introduced in the scientific literature to evaluate VGI, focusing on the PEV load management mechanisms. These mechanisms included dynamic pricing, demand response, and energy storage (vehicle-to-grid). The proposed methodologies in the literature aimed to address grid impacts of the PEVs considering a particular geographic region, and focusing on a specific grid operation. As discussed by Green et al. (2011), however, these studies did not adequately consider variances and uncertainties in consumer behavior and electricity market conditions. They also usually ignored PEV impacts on the distribution system with a higher interest in wholesale-level grid operations. These two issues remain a gap in the literature that needs to be addressed.

To address the problems mentioned above, this study introduces a stochastic

methodology for quantifying technical and economical impacts of VGI. The most basic form of load management, dynamic pricing, is considered in evaluating the impact of the PEV load on various hourly electricity demand curves and distribution networks. The proposed model is demonstrated in the Sacramento Region, where a mid-size utility company currently provides dynamic pricing programs for PEV consumers. This study considered a widespread PEV adoption scenario where 60,000 PEVs are deployed in the region, and all of these PEVs are used as commuter vehicles during the weekdays only.

The stochastic variables such as PEV charging levels (kW), commuter daily energy needs (KWh), and daily home arrival and departure hours are randomly assigned to the PEV households based on given statistical distributions. The Monte-Carlo simulations are repeated until the variances among the output data become minimal. For dynamic pricing scenarios, consumer adoption of the load management is presented as an optimization problem, where the each PEV consumer adopt the most economical charging schedule based on the electricity rates and their individual transportation needs. The major datasets in the model included the following; (1) projected PEV charging levels from Sacramento Municipal Utility District, or SMUD, (Berkheimer et al., 2013), (2) commuter daily vehicle-miles traveled (VMT) from US Census (2013), (3) daily home arrival/departure data from Sacramento Area Council of Government (SACOG, 2012), and (4) SMUD's annual hourly total electricity demand data from Federal Energy Regulatory Commission (FERC, 2013).

The findings are expected to help stakeholders to evaluate grid capacity constraints on handling widespread PEV adoption, and the effectiveness of load management mechanisms. The outputs of the model included PEV impacts on the seasonal load curve, annual peak demand, and distribution system loading. These outputs are chosen as the focus of the model for several

reasons. Most importantly, the PEV load impacts on the annual-peak electricity demand have always been a concern for energy planners (see Leo et al. (2011) for the discussion). The maximum capacities for the grid components, including generation, transmission and distribution systems, are being set and, if necessary, upgraded based on the changes in annual-peak electricity demand. This event usually occurs during mid-summer heat waves for the Sacramento Region.

The distribution system has been another concern for widespread PEV deployment, especially in single-unit residential areas. In these areas, the distribution transformers are designed to deliver electricity for a limited number of households. Some studies (e.g. Moghe et al. (2011)) illustrated that if several households located in the same neighborhood charge their PEVs at the same time, this situation might cause reliability problems and require infrastructure upgrades. The proposed method aims to capture such potential PEV clusters in the distribution system through Monte-Carlo simulations.

The following section provides an analysis of the literature related to PEV-grid systems modeling. This analysis focused on a group of 16 selected studies that were conducted within the last ten years. The proposed modeling methodology is discussed in detail in Section 3.3, including assumptions and data gathering. In Section 3.4, the simulation results are presented in three topics including PEV load impacts on the seasonal load curves, PEV load impacts on the distribution transformers and, finally, the economic assessment of VGI. The results are compared for different load management scenarios. The findings from the analysis are summarized and discussed in Section 3.5.

3.2 LITERATURE REVIEW

The scientific studies related to VGI can be classified as system-level or device-level analysis. As discussed by Sovacool and Hirsh (2009) and Galus et al (2010), improvements to both technology and system are critically important for the successful implementation of VGI. The technological improvements refer to the efficiency and reliability developments in the hardware, including advanced PEV chargers and telemetry systems. On the other hand, system-level improvements are related to addressing economic, behavioral, and infrastructural challenges. The focus of this literature review is to present and compare scientific studies related to system-level assessments on VGI.

The studies on VGI modeling aimed to address the impacts of various numbers of PEVs in a particular grid region, and focused on a specific grid operation. Most of the studies also evaluated how a particular load management mechanism would perform for the chosen PEV-grid system. In this review, the literature is categorized based on their focus of grid operations. These grid operations include (1) wholesale electricity markets, (2) economic dispatch of the generation, and, finally, (3) distribution system overloading. In the following paragraphs, the strength and weaknesses of the relevant studies on VGI will be discussed in detail.

The studies related to wholesale electricity markets focused on estimating market value of PEV demand response and energy storage (V2G). The wholesale markets mostly included frequency regulation and reserve markets. These studies often introduced a direct load control (DLC) algorithm, and modeled their algorithms as complex optimization models. The main focus has been evaluating performance of a DLC algorithm, which could be potentially implemented as a demand response or V2G program in the market. For instance, Kempton et al. (2008), Quinn et al. (2010), Andersson et al. (2010), Pillai-Bak Gensen (2011), and Han et al (2011) evaluated the value of V2G for participating in both regulation and reserve markets for different regions of

the US and EU. On the other hand, Sortomme and El-Sharkawi (2011) and Bessa et al (2013) investigated the value of PEV demand response for the reserve markets only. Sortomme and El-Sharkawi (2011) considered a scenario where 10,000 commuter PEVs participate in reserve markets during the daytime from 8am to 5pm. The authors used historical market data from Bonneville Power Administration. Similarly, Bessa et al. (2013) considered a scenario where 3000 PEVs participate in the Iberian electricity market during 2011-2013.

These VGI modeling studies on electricity markets present two common, major weaknesses. First, they use the historical market data and ignore the fact that the market participation of a large fleet of PEVs can greatly reduce the market value of regulation and reserves. For instance, Quinn et al (2010) considered 96,000 PEVs in their analysis. Such an amount of PEVs may saturate the regulation market in a real-world scenario and decrease the market value significantly. The second major weakness that is observed in these studies is the primitive representation of consumer behavior. These studies usually ignored the variances and uncertainties related to consumers' PEV charging hours and charging levels. They considered a "typical" PEV battery and commuter travel hours and presented their results as single-point estimates.

The second group of studies on VGI modeling concern the VGI impacts on the electricity generation dispatch. These studies usually formulate an optimization problem regarding the economic dispatch of resources, considering a particular generation mix. These studies present some major advantages. They have the ability to calculate greenhouse gas (GHG) emissions that would result from PEV charging. For instance, Lund and Kempton (2008), Axsen et al. (2011), Dallinger (2012), Sohnen (2013), and Kim and Rahimi (2014) evaluated GHG impacts of PEV charging in different regions. Additionally, some models (e.g. Lund and Kempton (2008),

Dallinger (2012), and Sohnen (2013)) evaluated how PEV charging would correspond to the renewable electricity generation. Although these studies present advantages over GHG emission calculations and renewable integration assessments, they usually ignore the complexities involved in demand response and energy storage. These studies present a scenario-based assessment approach, where all, or a certain percentage, of PEV consumers adopt a particular charging schedule at the same time. By assuming the existence of a central control mechanism over the electricity generation, these studies also ignored external impacts on the economic dispatch of the resources (e.g. wholesale market conditions).

Finally, studies on the distribution systems focus on the impacts of PEV charging on the distribution infrastructure such as substation transformers, neighborhood transformers, feeders, and underground cables. For instance, Soares et al. (2010), Moghe et al. (2011), and Shao et al (2012) evaluated impacts of PEV loads over the distribution systems. These studies usually present the highest level of stochastic analysis among the VGI modeling efforts. Because of the limited market data on PEV adoptions, the researchers in this field used Monte-Carlo simulations to randomly assign PEV locations in a chosen distribution system. Each study looked at different levels of the distribution infrastructure for different technical impacts such as system loading patterns, voltage drops, power losses, and aging of the infrastructure. Besides their advantages from stochastic modeling and detail-oriented approach to infrastructure assessment, they only evaluated very small regions compared to the other two groups mentioned previously. The details on the PEV deployment scenarios and focus of the analysis for each study are presented in Table 3.1.

As seen on Table 3.1, the studies related to VGI modeling usually focus on either the generation or distribution side of the grid. In contrast to the literature, the proposed methodology

aims to evaluate both sides, considering variances and uncertainties in consumer behavior, for each analysis. Additionally, the economic assessment in the proposed model does not focus on the VGI value in wholesale markets (regulation or reserves). It rather focuses on the VGI value in terms of cost-effectiveness measures. These measures include avoided costs of energy procurement, losses, and infrastructure upgrades for the utility company compared to no VGI scenario with the same amount of PEVs. In Table-3.1, DLC refers to the studies including direct load control programs where a control algorithm is modeled as an optimization problem for the each PEV driver. These studies aim to capture behavioral aspects of the PEV drivers, which differ significantly from the studies with scenario-based load management models where the PEV drivers are represented as one fleet with average PEV driving and charging patterns.

Table 3.1: Summary of PEV-grid systems modeling literature

VGI Modeling Study	PEV Deployment Rate or Number	Region or Market	Load Management Scenario	Stochastic Inputs
<i>Studies on Electricity Market Value for PEVs</i>				
Sortomme and El-Sharkawi (2011)	10,000 (commuter-only)	Bonneville Power Admin.	Demand response: DLC*	None
Bessa et al. (2013)	3000	Iberian Electricity Market (2009-2011)	Demand response: DLC	PEV locations, battery size
Kempton et al. (2008)	100 and 300	PJM (2004-2006)	V2G: Scenario-based	None
Quinn et al. (2010)	96,000	CAISO (2006-2008)	V2G: DLC	None
Andersson et al. (2010)	500	Sweden & Germany (2008)	V2G: DLC	None
Pillai and Bak-Gensen (2011)	9000 and 18,000	Western Denmark	V2G: Scenario-based	None
Han et al. (2011)	1000	PJM (2004)	V2G: DLC	Charge levels
<i>VGI Studies on Generation Dispatch and GHG Impacts</i>				
Lund and Kempton (2008)	1.9 million	Denmark	V2G: Scenario-based	None
Axsen et al. (2011)	1 million (3.6% of LDV fleet)	CAISO	Demand response: Scenario-based	None
Dallinger (2012)	12 million	Germany (2030)	V2G: DLC	Energy needs
Sohnen (2013)	1 million (4.5% of Households)	CAISO	Demand response: Scenario-based	None
Kim and Rahimi (2014)	1 to 160 million	Los Angeles, CA (2012-2040)	Demand response: Scenario-based	None
<i>VGI Studies on Distribution Systems</i>				
Soares et al. (2010)	25% and 50% of LDVs	Flores Island	Unmanaged charging	PEV locations, charge levels, battery size
Moghe et al. (2011)	10% to 100% of LDVs	Phoenix and Seattle (selected areas)	Demand response: Scenario-based	PEV locations
Shao et al. (2012)	100	Blacksburg, VA (Virginia Tech)	Demand response: DLC	PEV locations, energy needs, charge duration

* "DLC" stands for direct load control where a control algorithm is modeled as an optimization problem for the each PEV driver.

3.3 SYSTEM DESIGN AND DATA GATHERING

As has been discussed in the previous section, deterministic modeling approaches to VGI imply an excessive amount of assumptions in the system, and ignore the variances and uncertainties in real-world conditions. On the other hand, the stochastic approach acknowledges random patterns of some input parameters in the system, and features a range of outputs considering this randomness (Kulkarni, 2009). In this study, the proposed VGI model is designed based on two major stochastic processes. These processes are PEV-related electricity consumption of households, and PEV locations on neighborhood transformers. The following figure (Figure 3.1) presents the system inputs, outputs, and scenarios. As seen on Figure 3.1, the two major outputs resulting from the proposed analysis are (1) total hourly electricity consumption profiles for the region, and (2) numbers of overloaded neighborhood transformers in the grid system related to the additional load from PEV charging.

On the other hand, these outputs are expected to vary depending on the hourly electricity rates. The rates (TOU scenarios) included in this study are; (1) business-as-usual (BAU) scenario where the general fixed price is provided to PEV household, (2) HH-TOU scenario, which is an opt-in TOU rate that is currently being provided to households regardless of owning a PEV, (3) PEV HH-TOU scenario, which is a TOU rate that is being offered for households owning a PEV, and (4) PEV-TOU, which is a TOU rate offered for only PEV charging through a separate utility meter. At the time of this study, PEV owner households in SMUD territory were provided these four rate options.

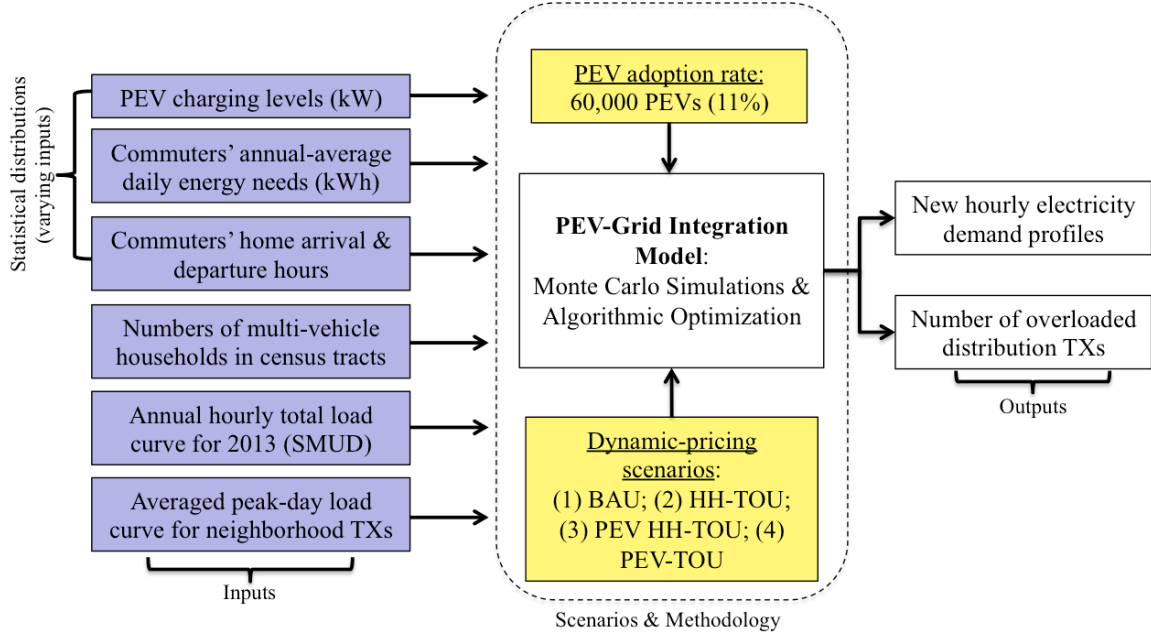


Figure 3.1: The conceptual design for the proposed PEV-grid systems model (note: “TX” stands for transformer; “HH” stands for households)

The proposed model requires data gathering for seven input parameters from transportation and electricity sectors. These datasets are mostly related to commuters’ travel hours, daily vehicle-miles traveled (VMT), power levels of their PEV charging, and regional characteristics of household vehicle ownership. Each of these datasets will be discussed further in the following part (3.3.1). Collaborating with these inputs, the proposed model calculates household-level electricity consumption for the 60,000 PEV owner households for a 24-hr weekday period. In dynamic pricing scenarios, the calculations for household-level electricity consumptions are repeated for different electricity prices where individual PEV owners choose the cheapest PEV charging option that does not interfere with their daily transportation needs. The origins of the reference value for PEV deployment and electricity pricing scenarios for PEV load management will be discussed in the following part (3.3.1) in detail.

As seen in Figure 3.1, three of the input datasets are clustered as being *distributions*, including commuters’ PEV charging levels, home arrival & departure hours, and daily energy

needs. These inputs represent probability distributions independently varying for the each household in the system. The values for each varying-input are assigned to individual PEV households randomly based on the given statistical distributions. This task is achieved by a method called inverse transformation (or Smirnov transform) (Kroese et al., 2011). As the first step in this process, the proposed model generated sample numbers for the varying-inputs and assigned these numbers to each household. At the end, the distribution of values for 60,000 households becomes equivalent to the given statistical distribution.

The process of random number generation is repeated 1000 times for the each household in so-called Monte-Carlo simulations. The Monte-Carlo simulations can provide useful insights in evaluating how different combinations of the independently varying-inputs effect the final outcome (Kroese et al., 2011). Besides the varying inputs, Monte-Carlo simulations are also used for the distribution system analysis in the random assignment of PEVs to individual households. The use of the Monte-Carlo simulations will be described further in the following paragraphs.

3.3.1 System Inputs

PEV Deployment. In this study, the reference value for PEV deployment is chosen as 60,000 PEVs in the Sacramento County. This amount corresponds to the state of California's 1.5 million PEV deployment goal, and is adjusted based on the ratio of number of households to local utility in Sacramento County (4% of the California households are located in Sacramento County).

The amount of 60,000 PEVs corresponds to 11.5% of the adoption rate (11% of households) considering all households, or 17.9% considering only single-unit households in the Sacramento County (US Census, 2013). The proposed model considers the use of these PEVs for work-related travel only. This assumption may result in less energy consumption than in reality. However, the other assumption that all vehicles will be used in commuting may balance this

decrease because not all vehicle owners drive to their workplace in their own car, but may carpool. For instance, about 80 % of the commuters in Sacramento Region, drive alone to their workplace (US Census, 2013).

PEV Charging Levels. In VGI modeling, the allocation of PEV charging levels is a very important factor that has temporal and spatial impacts on the results. In this study, a probability distribution for PEV charging levels is obtained from the electric transportation department at Sacramento Municipal Utility District. According to SMUD's projections (Berkheimer et al., 2013), the distribution of vehicles charging at Level-2 rates (>1.4 kW) will roughly double in a widespread PEV adoption scenario, relative to the time that SMUD conducted this projection. Such an assumption increases the share of 3.3 kW charging from 12% to 25%, and additionally, the share of 6.6 kW charging from 14% to 33% (Berkheimer et al., 2013). Although, the share of Level-1 charging has decreased compared to today's numbers, it still exists as the dominant charging level at 41% in SMUD's projections. The probability distribution for PEV charging levels are presented as histograms in Figure-2 along with other varying input parameters.

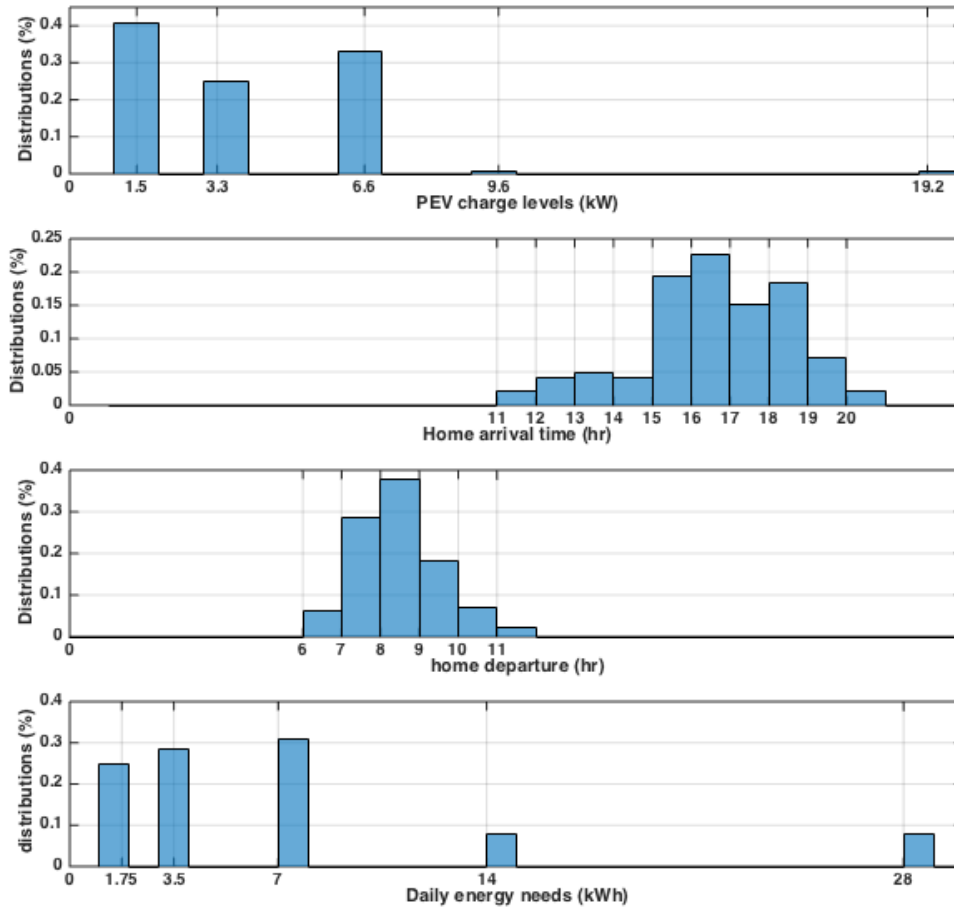


Figure 3.2: Statistical distributions of the varying inputs for Sacramento County

Home Arrival/Departure Hours. The distribution for commuters' home arrival hours is gathered from the regional air quality management district, Sacramento Council of Governments (SACOG), which conducts transportation-related surveys and planning work as a part of their air pollution assessments in the Sacramento County and surrounding areas. This dataset (SACOG, 2012) considers work-related and school-related travel data for the weekdays, which fits well within the focus of the proposed model. The time frame for commuter home arrivals is chosen between 11am to 8pm, ignoring the hours that correspond to less than 2% of the commuter arrivals in order to simplify calculations. As seen on Figure-2, the peak for home arrival hours rises at 4pm with 22%.

On the other hand, home departure hours are assumed to be directly linked to the home arrival hours in order to prevent any overlaps between home arrival and departure hours, which may exist if both are assigned to individual households randomly. In this regard, the commuters who arrive home early are assumed to be leaving home early. For instance, the commuters who arrive home between 11am and 12pm are assumed to have left home at 6am. The overall calculated distribution of home arrivals correlates to 92% in the actual survey data. The home departure hours are limited between 6am to 11am. Such an assumption ignores only the departure hours that correspond to less than 2% of the commuter departures in the actual survey data. According to this distribution, the peak for home departure hours is 37% and occurs at 8am.

Commuters' Daily Energy Needs. The distribution for daily energy needs is calculated based on the daily commuter vehicle-miles traveled (VMT) data. This data is gathered from the PEV Market Tool software, which features census block-level VMT distributions based on the commuter workplace location data from Origin-Destination Employment Statistics under Longitudinal Employer-Household Dynamics (US Census, 2014). The VMT distributions range from 5 miles to 80 miles daily, being most frequent at 20 miles at 31%. Such distribution corresponds to a mean value of 19.2 miles, which is slightly lower than the overall daily VMT average for the Sacramento region. Finally, these VMT values are converted to daily energy needs by using a 35kWh per 100 miles conversion ratio as suggested by Berkheimer et al. (2013), in their VGI study. As seen on Figure 3.2, according to this conversion the daily energy needs for commuters range between 1.75 kWh and 28 kWh.

The input parameters explained above are all related to the household-level electricity consumption, which only take temporal considerations into account. However, the following two parameters will be related to the distribution system impacts of the PEV load, which have both

temporal and spatial dimensions. Among the distribution system components, neighborhood transformers at single-unit residential areas have been the focus in this study. Our previous research (Chapter-1) showed that utilities are mostly concerned with the potential PEV clusters in single-unit neighborhoods. In these areas, transformers and related-cabling have much more limited capacity compared to transformers in multi-dwelling or commercial areas.

Household Vehicle Ownership. A recent study by Tal and Nicholas (2013) found that the multi-vehicle ownership, high-income levels, detached house ownership, and single vehicle commuting are all very common attributes within growing PEV market. Following this information, it is assumed that the single-unit households having two or more vehicles will be most likely to adopt a PEV once PEVs reach a significant market share. A tract-level household vehicle ownership data is gathered from the 2013 American Community Survey. This data on multi-vehicle ownership for each census tract correlates 74% with the number of high-income households, and 91% with the number of households with single driver commuters. These values support the usability of household multi-vehicle ownership data to project future PEV locations in a particular territory.

The census tract-level vehicle ownership data is used for the initial spread of the PEVs in the census tracts. The second spread of PEVs is performed for the households under the same census tracts following a uniform distribution. Therefore, it is assumed that the households within the same census tract have the same likelihood for adopting a PEV. The uniform spread of the PEVs to the households is repeated through Monte-Carlo simulations. It is expected that PEV clusters will be observed within some of these random simulations. Hence, the impact on the distribution system can be evaluated for both the average and marginal cases. As seen in Figure 3.3, for 317 census tracts, the numbers of households having two or more vehicles range between

0 and 2664, with a mean of 875 and a total of 277,283 ($\sigma = 458$). When PEVs are spread onto the census tracts based on the rates of multi-vehicle ownership, the numbers of PEV owner households range from 0 to 576, with a mean of 189 and a total of 60,000 ($\sigma = 99$).

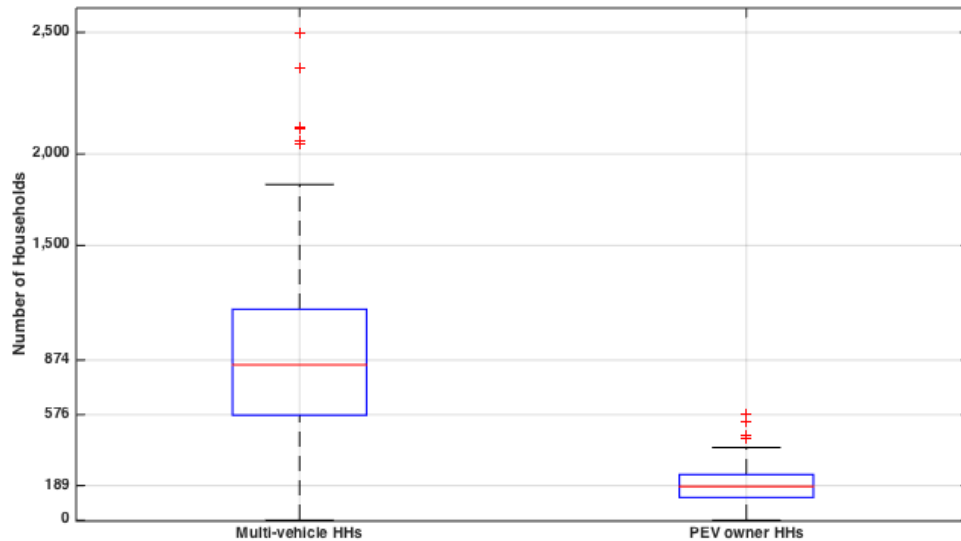


Figure 3.3: Box and whisker plots for the numbers of multi-vehicle owner households (HHs) and estimated PEV owner households for 317 census tracts in Sacramento Region

Loading Characteristics of Neighborhood Transformers. It is assumed that the neighborhood transformers reach their maximum utilization rate during the annual peak demand, which happens on July-3 considering the electricity demand data from 2013 in SMUD territory (FERC, 2013). An assessment of PEV impacts on neighborhood transformers requires two major data. These data include (1) the numbers of households that are connected to one neighborhood transformer in the distribution system that is being investigated, and (2) hourly load curve for an average neighborhood transformer during the annual peak day. On average, SMUD prefers to serve power to 10 households through one transformer, in which the typical capacity rating for a single residential transformer is 50 kVA (Berkheimer et al., 2013). Following this information, the single-unit households under each census tract are clustered randomly into groups of 10 to represent a neighborhood transformer. Some census tract does not include any single-unit

households. Hence, the numbers of transformers range from 0 to 335 with a total of 33,413 and a mean of 105 ($\sigma = 55$).

The estimated load curve for a typical neighborhood transformer on the peak day is provided by SMUD as presented in Figure 3.4. Here, the hourly load values are calculated by averaging a representative sample of transformers in the system. As seen in the figure, the total power flow on a transformer reaches 27.5 kW between 5pm and 6pm, leaving about 22.5 kW spare capacity for PEV charging. This amount (hourly spare capacity or load tolerance) ranges from 22.5 kW during on-peak hours to 39.8 kW during off-peak hours. Considering the variances in the neighborhood level electricity consumption, the hour load values are assumed to fluctuate $\pm 10\%$ around the reference value for the each neighborhood transformer. In a given hour period, if the total PEV load on a transformer is higher than the spare capacity, then it is assumed that the transformer is overloaded and needs an upgrade. The cost of transformer replacement for SMUD is given in Part 3.4.2.

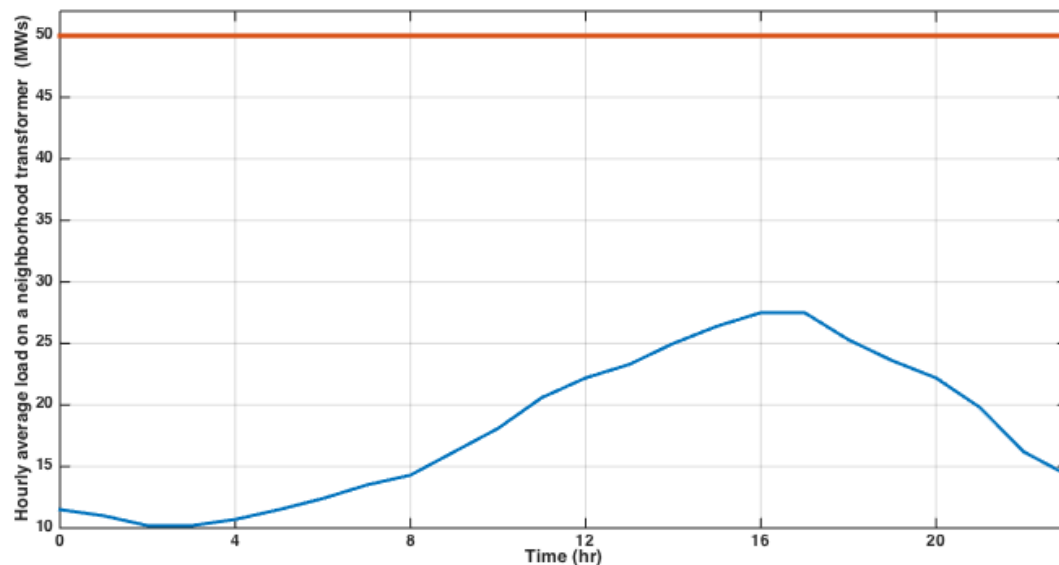


Figure 3.4: The hourly load curve (blue) and capacity (red) for a typical neighborhood transformer during the annual peak day in SMUD's territory in 2013 (data is gathered from SMUD (Berkheimer et al., 2013))

3.3.2 Load Management Scenarios

The load management scenarios in this study include three types of dynamic pricing mechanisms for PEV consumers. These mechanisms are all time-of-use (TOU) rates, with different rate schedules. These rates schedules are gathered from the utility company website as offered to PEV consumers within SMUD territory at the time of the study (SMUD, 2013). The potential PEV impacts on the grid system are investigated by comparing TOU scenarios to the business-as-usual (BAU) scenario where fixed rates were considered only. The three types of TOU rates included; (1) the regular household TOU (HH-TOU) rates which are offered to all customers, (2) PEV owner household TOU (PEV HH-TOU) rates which are offered to the households owning PEVs, and, finally, (3) PEV-only TOU (PEV-TOU) rates where the rates are offered for PEV charging only through a separate utility meter. As the target group is narrowed down, in options (2) and (3), the rates usually have higher on-peak rates and lower off-peak rates, which potentially make them more effective compared to regular HH-TOU rates.

These three TOU rates and the BAU scenario resulted in eight separate pricing scenarios because of the differences between winter and summer pricing for each case. Winter rates range from October 1 to May 31, where summer rates range from June 1 to September 30. On average, SMUD implements higher electricity rates during the summer because of the changes in the electricity consumption. As seen in Figure 3.5, the electricity demand profiles in the region changes significantly during summers. During winters, there is a slightly higher electricity demand between 6am-9am compared to the average. On the other hand, the electricity consumption increases significantly during summers starting early in the afternoon until 9pm. This increase, which peaks between 5pm and 6pm, happens due to the air conditioner loads during hot and dry summers in the region. These significant changes in electricity demand

profiles, and also the wholesale market conditions in summer, result in higher electricity prices accordingly.

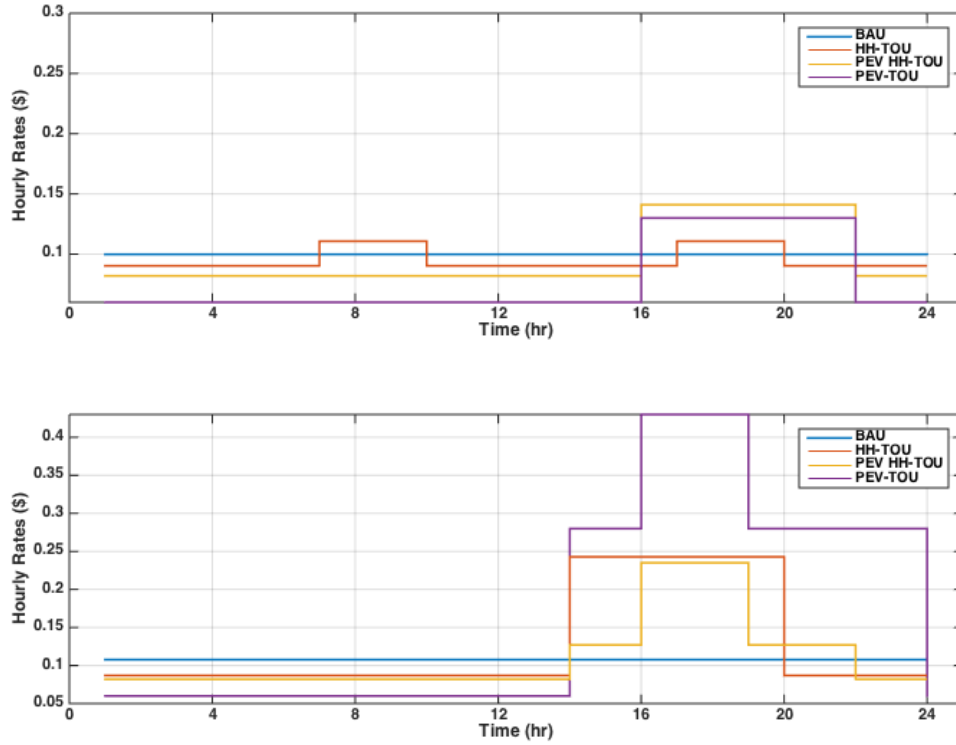


Figure 3.5: Hourly seasonal electricity rates for winter and summer rate schedules, respectively (source: *smud.org*)

The seasonal electricity prices for different TOU scenarios are presented in Figure 3.5. During winters, the HH-TOU rates reflect the morning and evening peaks. On the other hand, the evening peak is extended (4pm-10pm) and morning peak is ignored for simplicity in PEV HH-TOU and PEV-TOU rates. During the summer, the afternoon peak period starts at 2pm for all TOU rates, and in one case (PEV-TOU), the higher prices continue until mid-night.

3.3.3 PEV Consumers' Optimization Problem

The proposed methodology assumes that all PEV consumers “optimally” respond to TOU rates when offered. They choose the earliest PEV charge start time among the options which result in lowest charging costs (the time required for PEV charging does not change). Depending

on the energy needs, charging level, and commute hours, some PEV consumers may not have any flexibility in their PEV charge start time while others may have many options. This optimization scenario is chosen to present the maximum potential behavioral change that can be reached in total from a particular load management mechanism. A conceptual representation of the PEV consumers' optimization problem is presented in Figure 3.6. As seen on the figure, PEV buyers' decide on the "charge start time" considering their individual constraints regarding commute hours and daily energy needs. The individual optimization problems in dynamic pricing scenarios are solved for 60,000 PEV commuters in Monte-Carlo simulations 1000 times. The outcomes from these simulations will be discussed in detail in the following section.

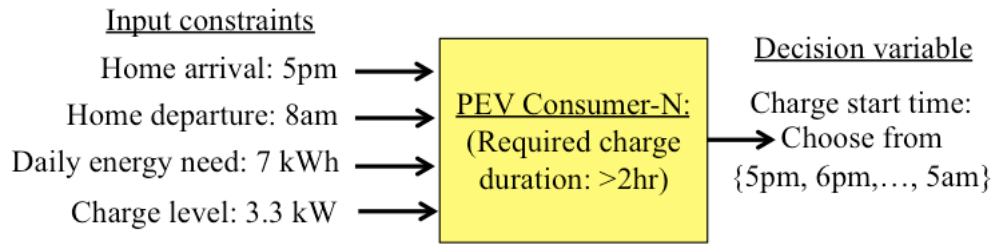


Figure 3.6: An example of the PEV consumers' optimization problem for the given inputs

3.4 RESULTS

In this part of the paper, the proposed VGI assessment methodology is applied, and the results are presented for the case of the Sacramento Region. The results are categorized under the PEV load impacts and the economic assessment of VGI. PEV load impacts included the changes in the seasonal electricity demand profiles for the utility region, and the PEV load impacts on the distribution system loading. The changes in the electricity demand profile may have especially important implications for grid operations such as economic dispatch of the generation, and required ancillary grid services. These potential changes will be discussed. The economic assessment has been conducted by using the hourly cost/benefit estimates for potential electricity

savings (per MW/hr) provided by the E3 Cost-Effectiveness Calculator. This tool was developed by Energy, Environment, and Economics (E3) to evaluate cost-effectiveness of load management programs. The content and details of the model will be discussed further in part 3.4.3.

3.4.1 PEV Impacts on the Electricity Demand

The initial results (shown in Figures 7-8) include the hourly total PEV load for the BAU scenario where PEV consumers start PEV charging as soon as they arrive home. This simulation is repeated 1000 times. The variance among the results has been very low. For instance, the peak demand, which occurs at 6pm, varied between 85 MW to 88 MW, with a mean of 86 MW. A 3MW change would be difficult to notice in SMUD's total load curve, considering its annual average peak in 2013 was 1578 MW. The variance among the simulation results is investigated by the coefficient of variation, which is the ratio of the standard deviation to the mean. In applied statistics, the variance among the datasets is seen as small if the coefficient of variance is smaller than one (<1). Overall, the average coefficient of variation for the 24hr load data is found to be 0.0207. As seen on Figure-7a, variance is very stable after the 25th simulation, approaching 0.015. This low variance can be also observed in the PEV load curves in Figure-7b. Considering this low variance in the hourly PEV load, only the mean values are presented in the following analysis in Part 3.4.1.

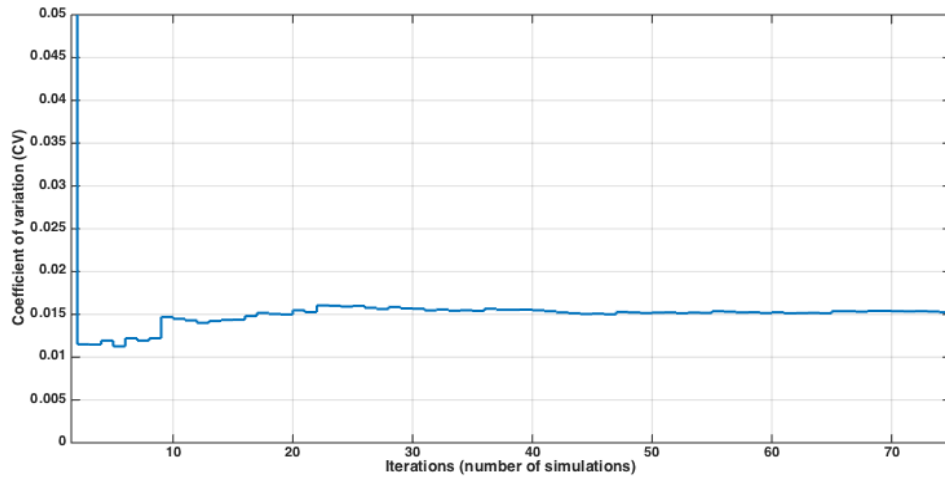


Figure 3.7a: The changes in coefficient of variation among the results on hourly PEV loads, BAU case.

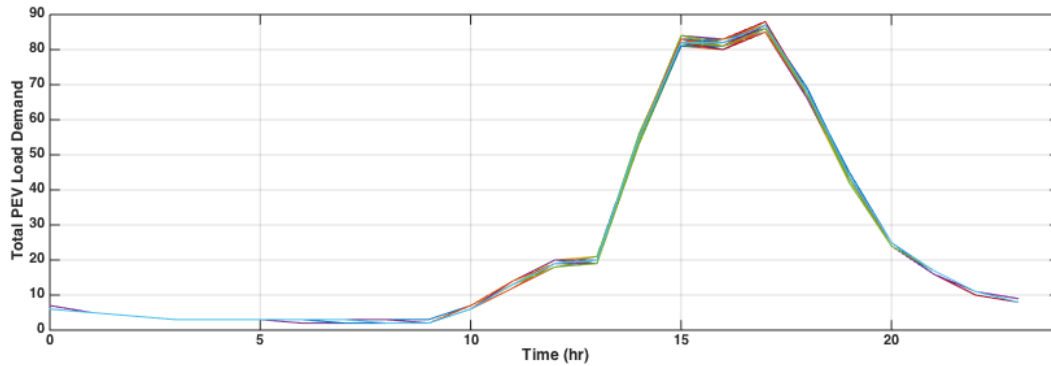


Figure 3.7b: The total electricity load from 60,000 PEVs repeated 1000 times. BAU case.

The total PEV charging load is added to SMUD's seasonal electricity demand curve in the following chart (Figure 3.8). As expected, the hourly PEV load pattern has not been changed between summer and winter in the BAU scenario. The PEV impact becomes more significant (above 50MW) between 3pm and 8pm in both seasons. This additional PEV load increased the winter peak by 68 MWs, where summer peak is increased by 86MW. This increase is observed due to summer peak overlaps where the peak for PEV load is at 6pm. As discussed previously, the increase in summer peak has always been a concern for electricity planners. Such peaks risk grid reliability, increase high amount of investments for the capacity increases in generation and distribution systems. Therefore, the peak shaving ability of load management mechanisms is expected to be an important factor in the assessment of their success.

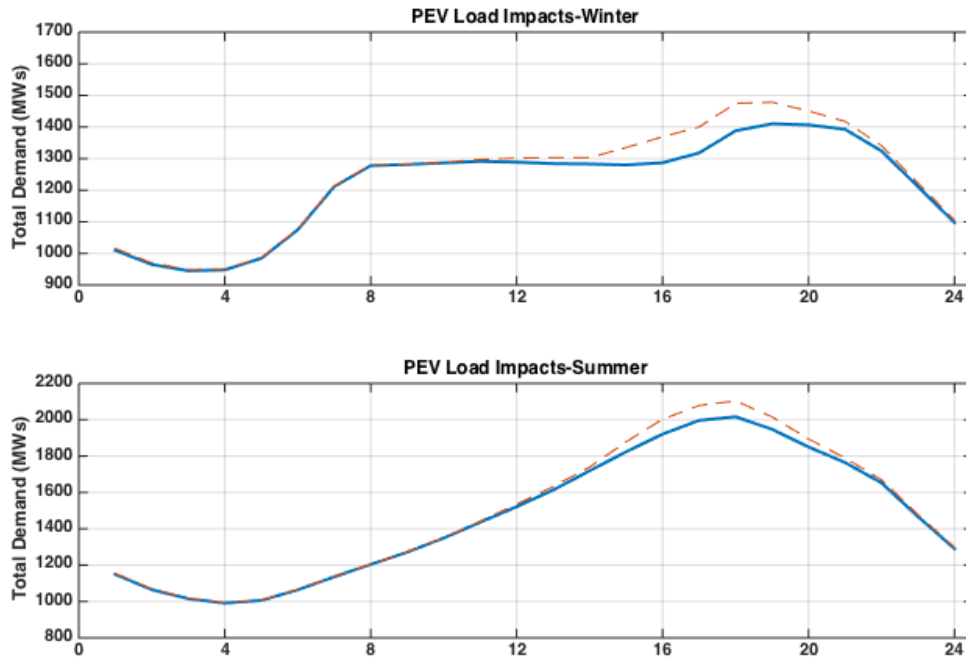


Figure 3.8: The estimated PEV load added to the SMUD's total electricity demand from 2013, BAU case.

The total PEV load for TOU scenarios are calculated for summer and winter seasons. As seen in Figure 3.9, TOU rates successfully shifted additional load from the peak hour to later hours. However, there is 3MW of load that could not be shifted for both winter and summer peaks because of those commuters who do not have any flexibility on their PEV charging time. These results show that only about 3.5% of the peak increase resulting from PEVs cannot be shifted to off-peak hours by the TOU rates. On the other hand, all of these three TOU rates created different smaller peaks on the system. The additional peak in winter season has been around 143 MW at 8pm for HH-TOU rate, and 178 MW at 10pm for PEV HH-TOU and PEV-TOU rates. Although the scenario (3) and (4) resulted higher peak compare to scenario (1), this higher peak occurred after 10pm. Therefore, it is expected to be more manageable for the utility company. The results on the peak PEV loads have been slightly different in the summer. All of the TOU rates resulted in the same amount of peak (209 MW) occurring at different times of the

day. For instance, PEV-TOU created 209 MW peak at 12am, which resulted in most of the PEV charging happening at night, between 12am-5am.

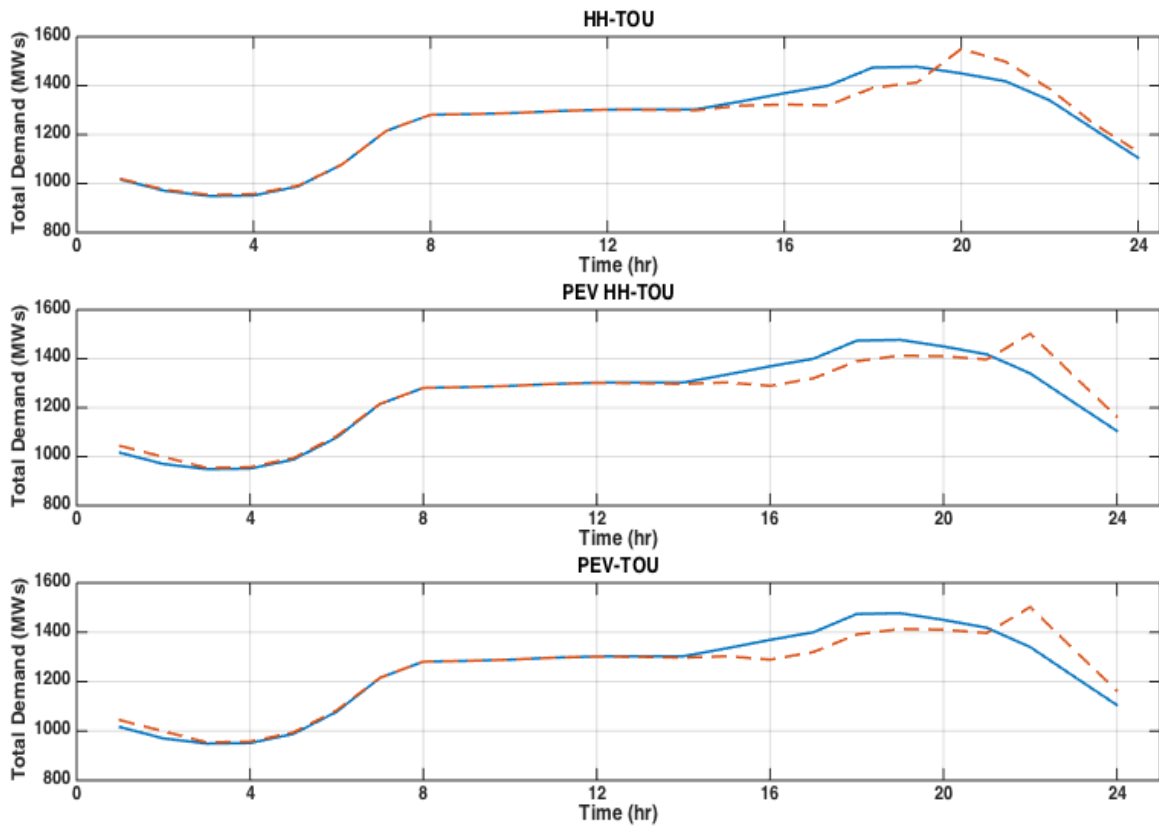


Figure 3.9a: The impacts of dynamic pricing of PEVs on the SMUD's total electricity demand for Winter-2013. TOU cases.

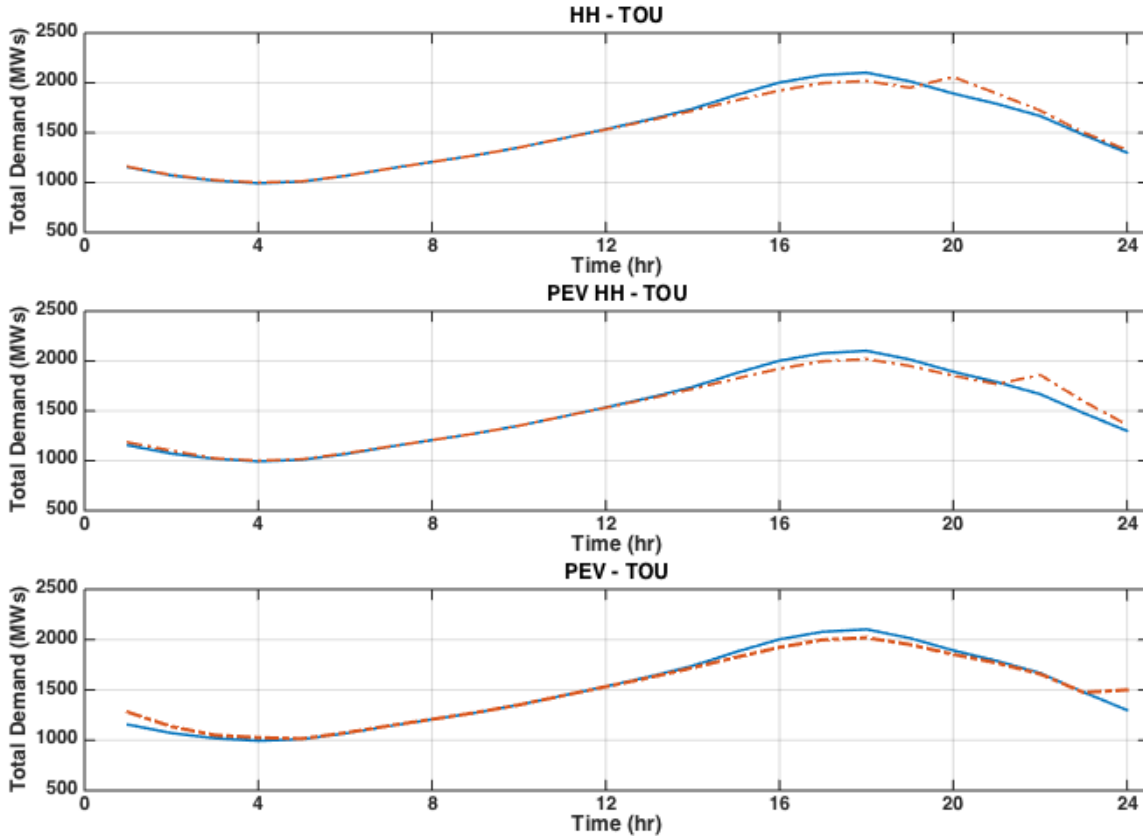


Figure 3.9b: The impacts of dynamic pricing of PEVs on the SMUD's total electricity demand for Summer-2013, TOU cases.

3.4.2 PEV Impacts on the Distribution System

As discussed previously, PEVs are expected to impact the distribution system loading, especially during the annual peak day. Based on the 2013 data, the annual peak demand occurred in SMUD on July 9th at 6pm. The potential impact of PEVs on the distribution system is evaluated through the random assignment of PEVs to the households for each census tract (see Part 3.3.1 for the details). To capture the variations among the neighborhood-level electricity consumption, it is assumed that the spare capacity for each neighborhood transformer fluctuates up to +/-10% around the average hourly spare capacity. This assumption is made based on Jardini et al. (2000)'s study, which shows that the hourly electricity consumption levels may vary around %10 among the households.

In contrast to the previous simulations (in Part 3.4.1), the results for PEV impacts on the distribution system varied significantly. For instance, for the BAU scenario, it is estimated that 42 to 101 distribution transformers (out of a total of 33,413) will be overloaded due to the PEV charging ($\sigma= 9.3$). As the proposed method considered a uniform distribution for the PEV spread, this variance occurred very naturally. The results with higher amounts of transformer overloads represent the cases in which the PEVs clustered in the same neighborhood more frequently compared to the average result. Based on this outcome, we can conclude that at least 42 distribution transformers will be overloaded in BAU cases, where this amount can reach up to 101 transformers if these PEV adoptions tend to cluster within the same neighborhoods. The comparison of results from TOU rate scenarios is provided in Figure 3.10.

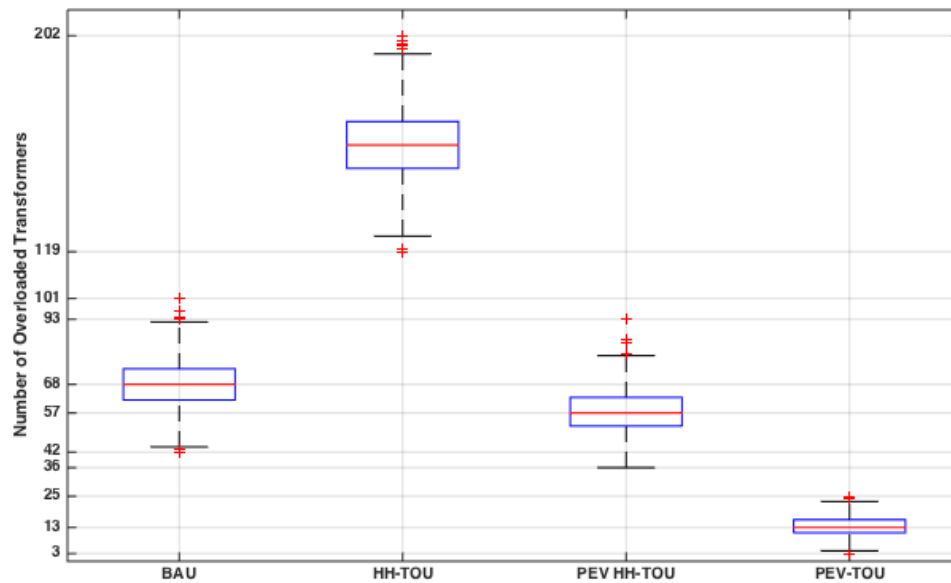


Figure 3.10: Box and whisker plots for the estimated transformer overloads in 1000 simulations with and without considering TOU rates

The findings above show that the dynamic pricing strategies may not necessarily benefit the distribution system. For instance, HH-TOU rates actually created a worse situation in terms of distribution system loading. The additional PEV load of 209 MW at 8pm increased transformer overloading potential from 101 to 202. On the other hand, PEV HH-TOU rates

resulted slightly lower amounts of overloaded transformers, comparing 93 to 101. Finally, PEV-TOU resulted in the best outcome. The maximum amount of transformer overloading is reduced to 25. Although, PEV-TOU provided the best outcome in terms of transformer system loading, it may not be the most cost-effective solution considering the additional infrastructure requirements due to the use of a separate PEV metering system. The economics of the PEV metering systems will be discussed in the following analysis.

3.4.3 Economic Assessment of VGI

The economic assessment of VGI is performed considering two aspects of PEV impacts: (1) the additional hourly load created by PEV charging and (2) the number of overloaded transformers resulting from this additional load. For utility companies, the hourly cost of the additional electricity delivered to the PEV households has several components. These components may include; (1) the cost of energy (generated by existing power plants only), (2) the cost of increased generation capacity required to supply the additional electricity, (3) the cost of ancillary grid services such as frequency regulation, (4) the cost of additional CO₂ emissions, and (5) the cost of energy losses that occurred within the transmission and distribution (T&D) systems (E3, 2014). All of these costs are very much time dependent and change hourly based on the seasonal weather conditions, local climate, and grid system loading conditions.

This study used the annual hourly-avoided cost estimates provided by a model called *E3 Calculator*. The E3 Calculator is a spreadsheet model that provides an estimate on the hourly cost of increased electricity demand considering various components of the electricity delivery described above (Horii and Cutter, 2011). This tool was originally developed to model the avoided costs of energy saved in the energy efficiency programs as requested by CPUC. The three largest utilities in California are required to perform an economic assessment for their

energy efficiency related programs, including demand response and energy storage, by using the hourly cost estimates provided by the E3 Calculator (CPUC, 2013). In the proposed analysis, the cost estimates for 2013 data within the Z12 climate zone is gathered from this software. A distribution of monthly average energy generation and delivery costs is presented in Figure 3.11.

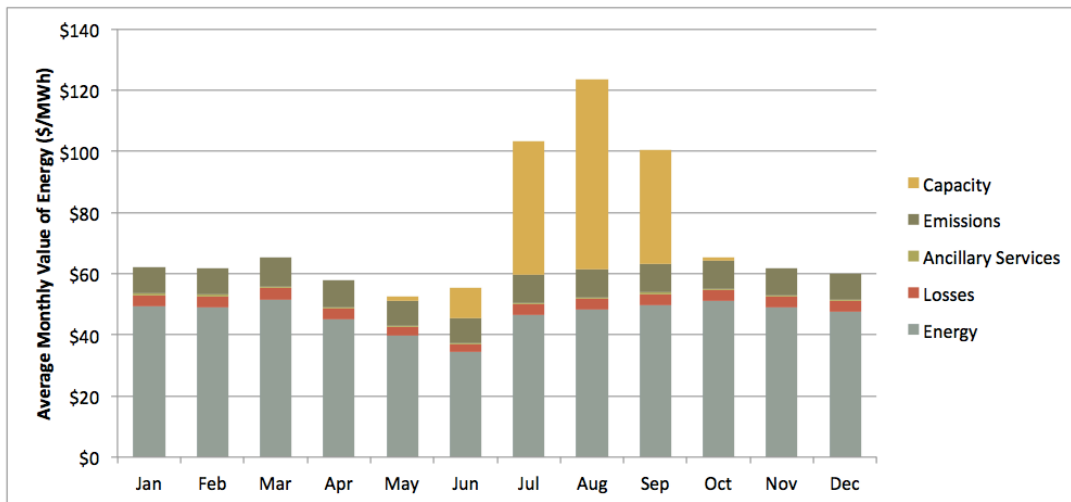


Figure 3.11: Monthly average value estimates of the saved electricity (per MWh) to an electricity provider located in Z12 climate zone in 2013 (E3, 2011)

As seen in Figure 3.11, the majority of the cost of the additional electricity demand occurs due to the cost of energy (generation). The second largest component of this cost is the capacity cost, which is estimated based on the historical data of investment decisions by the electricity providers in California and so-called *resource adequacy values* (see Horii and Cutter (2011) for the details). This cost becomes very significant between July and September. Due to this increase, the cost of delivering additional electricity per MW exceeds \$120. This amount stays under \$60 during April to June. The third most significant cost is the environmental cost due to CO₂ produced by the power stations. This cost seems to be very consistent, and is more dependent on the hour of the day than the month of the year.

The costs of additional electricity load due to PEV charging are calculated based on the hourly cost estimates from the E3 calculator. Only the weekdays are considered due to the

assumption that PEVs are used for commute purposes only. The results are provided in Table 3.2 for BAU and TOU scenarios. The annual cost of \$100,000 for the PEV-related program administration is added to PEV HH-TOU and PEV-TOU. According to this assessment, PEV-TOU provided the least cost option. The cost of PEV-related electricity delivery is reduced to about \$9 million from \$17 million in the BAU scenario. PEV-TOU, however, did not provide the highest value due to the significant decreases in expected revenues from electricity delivery. In this regard, PEV HH-TOU provided the highest value for the utility company, a net profit of \$3,838,536. Finally, the BAU scenario resulted in a net loss of \$216,658 for the utility company occurring annually.

Table 3.2: Annual cost and benefit estimates for each TOU rate scenarios

	BAU (reference)	HH-TOU	PEV HH- TOU	PEV-TOU
Total Annual Cost	\$17,389,040	\$11,409,565	\$10,168,485	\$9,801,648
Energy	\$9,669,550	\$8,170,908	\$7,111,418	\$6,767,068
Losses	\$787,993	\$562,470	\$457,312	\$436,300
Ancillary Services	\$127,837	\$78,402	\$43,713	\$42,542
Environmental (CO2)	\$2,255,451	\$1,955,862	\$1,814,628	\$1,805,501
Capacity Increase	\$4,548,210	\$641,923	\$641,415	\$650,237
PEV Program Admin	N/A	N/A	\$100,000	\$100,000
Total Revenue	\$17,172,382	\$15,076,355	\$14,014,198	\$11,158,139
Net Annual Profit (Utility)	-\$216,658	\$3,666,790	\$3,845,713	\$1,356,490
Net Annual Savings* (Utility)	N/A	\$5,979,475	\$7,220,555	\$7,587,392
Average Annual Cost of PEV Charging	\$286.21	\$251.27	\$233.57	\$185.97
Net Annual Savings (All PEVs)	N/A	\$2,096,028	\$3,158,184	\$6,014,244
Net Annual Savings (per PEV)	N/A	\$35	\$53	\$100

* “Net annual savings” are the savings relative to BAU scenario

The PEV consumers’ savings is also provided in Table 3.2. The BAU scenario resulted in an annual cost of \$286 for the commuting-related electricity consumption. This amount is

reduced to \$233 in PEV HH-TOU and \$185 in the PEV-TOU scenario. Although, PEV-TOU provided the lowest-cost electricity option for the PEV consumers, the additional metering system cost is expected to be significant. The current utility practices for separate utility meters require an additional electricity panel in the household, which may cost about \$2000 for the PEV buyer (see Chapter-2 for the discussion). Because of the limited market data on PEV metering systems, this study did not included the cost of PEV metering or telemetry systems in the economic analysis. It is expected that this cost will be impacted significantly by the utility policy developments such as enabling submetering systems for utility billing.

Finally, the cost of distribution upgrades are calculated and provided here as one-time occurring direct costs (see Table 3.3). The average cost of a transformer upgrade is provided by SMUD as \$7,691 (E3, 2014). Based on this value, the range in cost of transformer upgrades in the BAU scenario is found to be \$334,362 to \$804,062. This amount decreased as little as \$23,883 in the PEV-TOU scenario. Although a mid-size utility company can easily manage such a one-time occurring cost, the transformer overloading is seen as a serious problem because of the risk factors involved. If a transformer is overloaded unexpectedly, such a situation may result in temporary blackouts for the all neighborhood, which may impact both the PEV experience and the utility reputation negatively. Therefore, utility notifications of the PEV deployment and the PEV-related load tracking are valued as a critical aspect of VGI.

Table 3.3: Estimated costs for the distribution infrastructure upgrades related to PEV charging under various TOU rate scenarios

	BAU (reference)	HH-TOU	PEV HH-TOU	PEV-TOU
Estimated Cost Range	\$ 334,362- \$804,061	\$ 947,359- \$1,608,122	\$ 286,596- \$740,373	\$ 23,883- \$199,025
Average Cost	\$541,348	\$1,273,760	\$453,777	\$103,493
Cost Savings (Relative to BAU)	N/A	-\$732,412	\$87,571	\$437,855

The economic assessment above provided several cost and revenue estimates for the utility company and cost estimates for PEV consumers. This assessment can be expanded into a time-series analysis, where a comprehensive net-present value (NPV) analysis is performed considering several policy and market developments in the field. Additionally, the integration of residential solar panels into the model would provide more accurate values for both the consumers and the utility. These potential improvements on the model are left for future work.

3.5 CONCLUSIONS

This study introduces a stochastic methodology for quantifying technical and economical impacts of VGI. The most basic form of load management, dynamic pricing, is considered in evaluating the impact of the PEV load on various hourly electricity demand curves and distribution networks. The proposed model is demonstrated in the Sacramento Region, where a mid-size utility company currently provides dynamic pricing programs for PEV consumers. The findings contribute to both the methods used for PEV-grid systems modeling, and to the case study to evaluate PEV deployment for the Sacramento Region.

In terms of the methodological improvements, the proposed model provided an assessment for both generation and distribution systems, which is different than the studies mentioned in the literature review. Expanding the focus of the VGI analysis to both systems provided a more comprehensive picture on understanding PEV impacts. Additionally, the proposed methodology considered variances and uncertainties related to consumer behavior in higher detail. The varying-inputs related to consumer behavior included PEV charging levels, daily energy needs, home arrival/departure hours, and PEV locations (households).

The preliminary results show that, considering today's grid system, the deployment of 60,000 PEVs in the Sacramento Region will have a significant but manageable impact on the

utility grid operations. These impacts include increasing annual peak demand, and overloading distribution transformers, while having a very small impact on the total annual energy use. Providing dynamic-pricing signals to PEV drivers, however, may minimize these impacts depending on the rate schedules. Although, all TOU rates minimized the increases in peak demand, they did not necessarily mitigate negative impacts of PEV charging on the distribution system. This issue is highly dependent on the details of the rate schedule. Among the three TOU scenarios, the special TOU rate for PEV owner households (PEV HH-TOU) resulted in the highest economic value for the utility company.

The economic assessment in this study provided several cost and revenue estimates for the utility company and the PEV consumers. This assessment can be expanded into a time-series analysis, where a comprehensive net-present value (NPV) analysis is performed considering several policy and market developments in the field. Additionally, the integration of residential PVs can be considered. These potential improvements on the model are left for future work.

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CONCLUSIONS & FUTURE WORK

This dissertation features several important improvements for the VGI literature. The first paper provided an empirical study on an actual policy process in California, which constitutes an example for the other policy makers in the US, who consider similar policy actions related to VGI. The second paper identified existing technical and market challenges in VGI, which need to be considered by stakeholders in their VGI efforts including decision-making in policy proposals, financial investments, and demonstration projects. Finally, the third study provided a stochastic methodology for quantifying grid impacts of widespread PEV deployment and economic value from PEV load management.

Chapter 1 presented that a policy window for VGI was opened for the first time through SB626 in 2009, and later, supported by the Governor's ZEV action plan in 2012. These developments brought VGI into the agenda of a policy community that works on electricity and transportation-related energy planning issues. Empirical findings show that the Energy Division Staff in CPUC has been a policy entrepreneur among the participants of the policy process by introducing VGI-related regulations for the IOUs. CPUC's VGI regulations emphasized research, created an environment where stakeholders can discuss and try new solutions, and identified major issues that stakeholders should consider in the long-term. The empirical evidence suggests that the two largest barriers facing an effective policy solution have been (1) the complexities involved in quantifying economic value from VGI; and (2) the feasibility concerns about adopting VGI enabling technologies on the grid.

The empirical data shows that VGI stakeholders are currently in the phase of evaluating feasibility of various load management technologies from different perspectives such as data privacy, billing liability, and impacts on battery life. These evaluations are mostly being done

through demonstration projects managed by the utility companies. However, the existing model where utilities propose and manage these demonstration projects may not be an effective solution. As mentioned by several stakeholders, utilities currently do not have any significant incentive to develop innovative and cost-effective solutions for VGI. Alternatively, these VGI-related assessments can be performed by the third party research organizations closely collaborating with the utilities on issues such as data gathering, hardware installations and communicating with PEV consumers when necessary.

Chapter 2 provided a feasibility assessment for the PEV load management mechanism including dynamic pricing, demand response, and energy storage. The qualitative analysis presented that technical and market challenges exist in most of the load management strategies. Overcoming these challenges requires a strong dialogue between utilities and the PEV sector, especially related to PEV submetering, use of bidirectional chargers, and experiences with consumer engagement. Additionally, it is found that the stakeholders from utility and automaker sectors were highly skeptical about the near-term feasibility and economic value from V2G. Fleet vehicles have been mentioned as the only near-term application of such system.

Finally, Chapter 3 provided an assessment for both generation and distribution systems, which is different from the studies mentioned in the literature review. Expanding the focus for the VGI analysis to both systems provided a more comprehensive picture to understand PEV impacts. Additionally, the proposed methodology considered variances and uncertainties related to consumer behavior in higher detail. The varying-inputs related to consumer behavior included PEV charging levels, daily energy needs, home arrival/departure hours, and PEV locations (households).

The proposed model in Chapter 3 has significant potential for improvements, especially

for the economic analysis. In the future, the cost and revenue estimates for the utility company and the PEV consumers can be expanded into a time-series analysis, where a comprehensive net-present value (NPV) analysis is performed considering several policy and market developments in the field. Additionally, the integration of residential photovoltaics can be considered. These potential improvements are all left for future work.